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Surface Casing Depth Minimum Requirements

October 1997 Edition

Alberta Energy and Utilities Board

Surface Casing Depth Minimum Requirements

October 1997 Edition

Guide 8 Surface Casing Depth Minimum Requirements

17th Edition, October 1997

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1998

EUB Alberta Energy and Utilities Board

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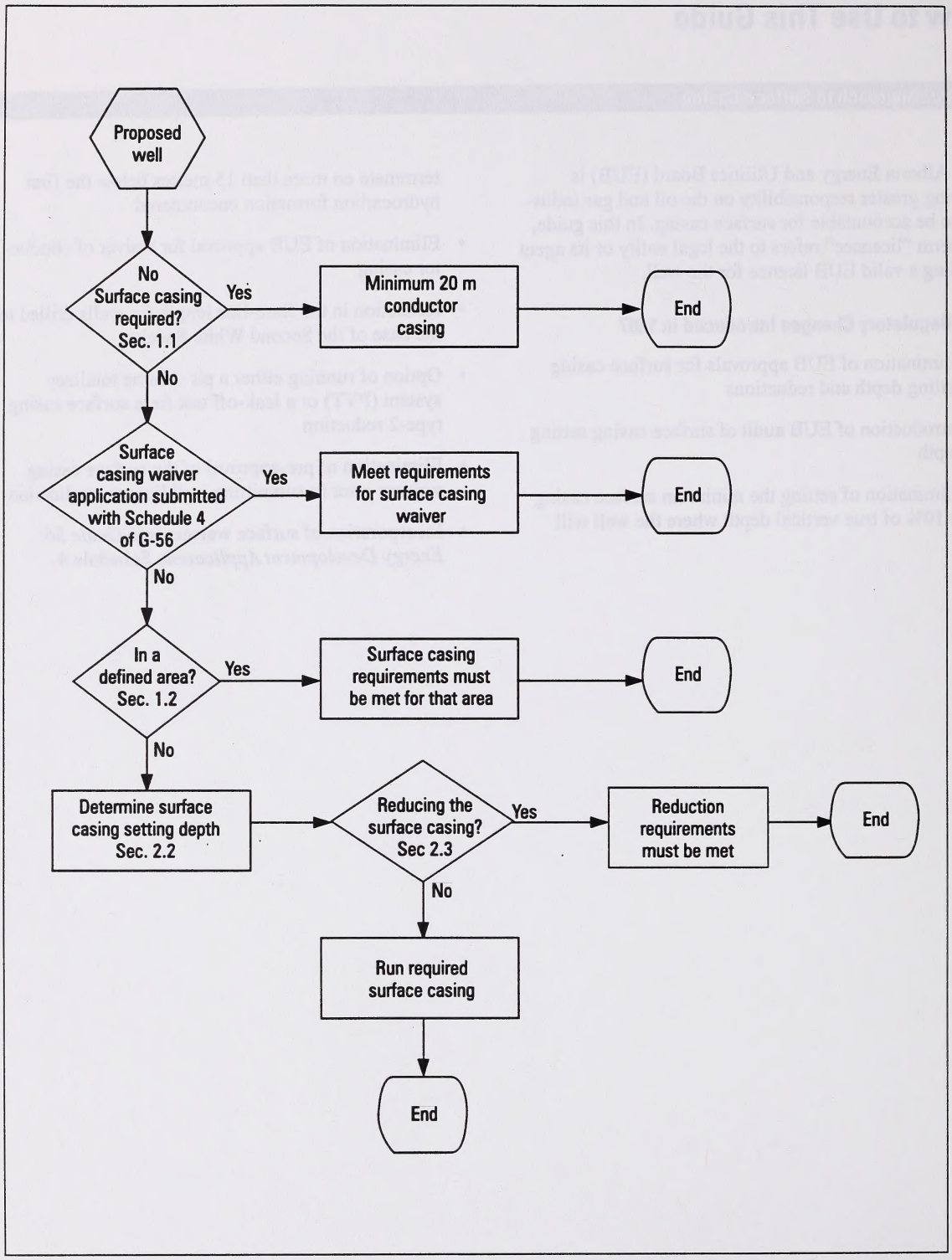
How to Use This Guide

A New Approach to Surface Casing

The Alberta Energy and Utilities Board (EUB) is placing greater responsibility on the oil and gas industry to be accountable for surface casing. In this guide, the term "licensee" refers to the legal entity or its agent holding a valid EUB licence for the well.

Key Regulatory Changes Introduced in 1997

- Elimination of EUB approvals for surface casing setting depth and reductions
- Introduction of EUB audit of surface casing setting depth
- Elimination of setting the minimum surface casing at 10% of true vertical depth where the well will terminate no more than 15 metres below the first hydrocarbon formation encountered
- Elimination of EUB approval for waiver of conductor casing
- Reduction in the flare-line length for wells drilled to the base of the Second White Specks
- Option of running either a pit volume totalizer system (PVT) or a leak-off test for a surface casing type-2 reduction
- Elimination of pre-approval of the surface casing waivers prior to submitting well licence application
- Incorporation of surface waivers into *Guide 56: Energy Development Application,* Schedule 4.



SURFACE CASING PROCESS

Overview of the Guide

The EUB prepared *Guide 8* to help the oil and gas industry better understand EUB expectations and requirements for setting surface casing and conductor casing, so that licensees will be confident about deciding setting depths and complying with EUB requirements. This guide explains the requirements for surface casing waivers and surface casing standards.

The EUB Facilities Division can trigger an audit any time after issuing a well licence. You must keep on file documentation showing that you have met the minimum requirements of *Guide 8*.

This guide is not all inclusive: it complements procedures and requirements set out in regulations and directives. The guide overrides EUB interim directives (IDs) when there is any discrepancy between the guide and them.

The guide has four sections, plus a related Appendices:

Section 1: Surface Casing Waivers

- Surface Casing Waivers—No Approval Required
- Surface Casing Waivers—Approval Required

For the definition of a surface casing waiver, see Appendix 1.

Section 2: Surface Casing Standards

- Surface Casing Check Sheet
- Minimum Surface Casing Setting Depths for Special Areas
- Completing the Surface Casing Check Sheet—Normal Surface Casing Required
- Completing the Surface Casing Check Sheet—Surface Casing Reduction

For the definition of surface casing, see Appendix 1.

Section 3: Conductor Casing Standards

- Requirements for Setting Conductor Casing

For a definition of conductor casing, see Appendix 1.

Appendices

Important references are cited throughout the text and detailed in the Appendices.

- Appendix : Definitions and Background Information—How to calculate surface casing setting depths and reductions
- Appendix 2: Formation Leak-Off Tests—Conducting and Reporting Procedure
- Appendix 3: References List—Where to obtain references cited but not included with this guide
- Appendix 4: Full Text of Cited EUB Interim Directives (IDs)

You are advised to read the *Oil and Gas Conservation Regulations*, Part 2, Sections 6.080 and 6.081, on the required depth of surface casing for wells in Alberta, and Section 8.135, Subsection 9(b), on equipment spacing.

Further Information

If, after you have read the appropriate sections of *Guide 8*, you require more information or assistance, contact the EUB Operations Group, Facilities Division (403-297-6952).

The requirements outlined in this guide take effect on 1 October 1997.

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Section 1

Surface Casing Waivers

Section 1: Surface Casing Waivers

1.0 Before You Begin

TOPIC	DESCRIPTION
Step 1	First determine if the proposed well is being drilled to the base of the Second White Specks in southeastern Alberta or as an oil sands core hole or oil sands evaluation well inside the surface mineable area. Section 1.1 describes the criteria to make this assessment.
Step 2	If the well falls within Section 1.1, then you may run 20 m of conductor casing. EUB pre-approval is **not** required.
Step 3	If the proposed well is being drilled • deeper than the Second White Specks in southeastern Alberta, • deeper than 200 m in the surface mineable area, • as a conventional well, or • as a heavy oil or oil sands well (Figure 1), then you must run surface casing (see Section 2.1) **or submit an explanation of why you are not doing so** in conjunction with Schedule 4 of *Guide 56*. The EUB will then review the circumstances and decide if an exemption is warranted.

1.1 Surface Casing Waivers—No Approval Required

You do not need EUB approval to run 20 m of conductor casing for wells drilled to the base of the Second White Specks in southeastern Alberta or for oil sands core holes and oil sands evaluation wells inside surface mineable areas.

Wells Drilled to the Base of the Second White Specks

The EUB does not require surface casing for wells drilled to the base of the Second White Specks formation in townships 1-29, ranges 1-21, and townships 30-37, ranges 1-13, west of the 4th meridian (Figure 2), if:

- a minimum of 20 m of conductor pipe is set and cemented in place,
- a Class 1A BOP system (defined in *ID 91-3*, see Appendix 4) is installed with a 152 mm flare line,
- the base of the Second White Specks does not exceed a depth of 950 m,
- the estimated potential absolute open flow (AOF) does not exceed 113 10^3m^3/day (see *Shallow Gas Flare Line Length Reduction*, Appendix 3), and
- the flare line terminates a minimum of 35 m from the well centre in an open tank at least 2 m high.

The EUB will not make exceptions to the above requirements.

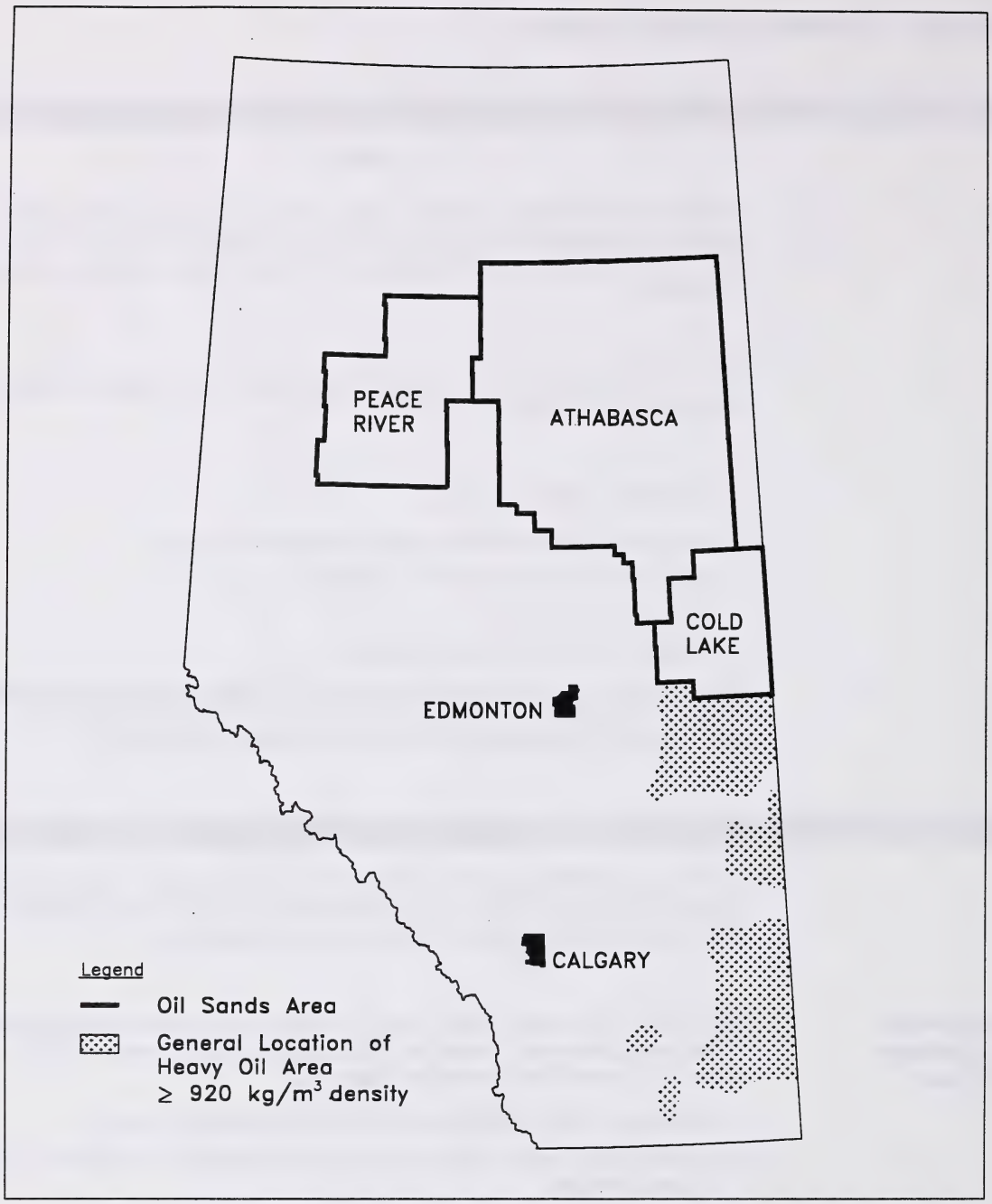

FIGURE 1 – OIL SANDS AND HEAVY OIL AREAS

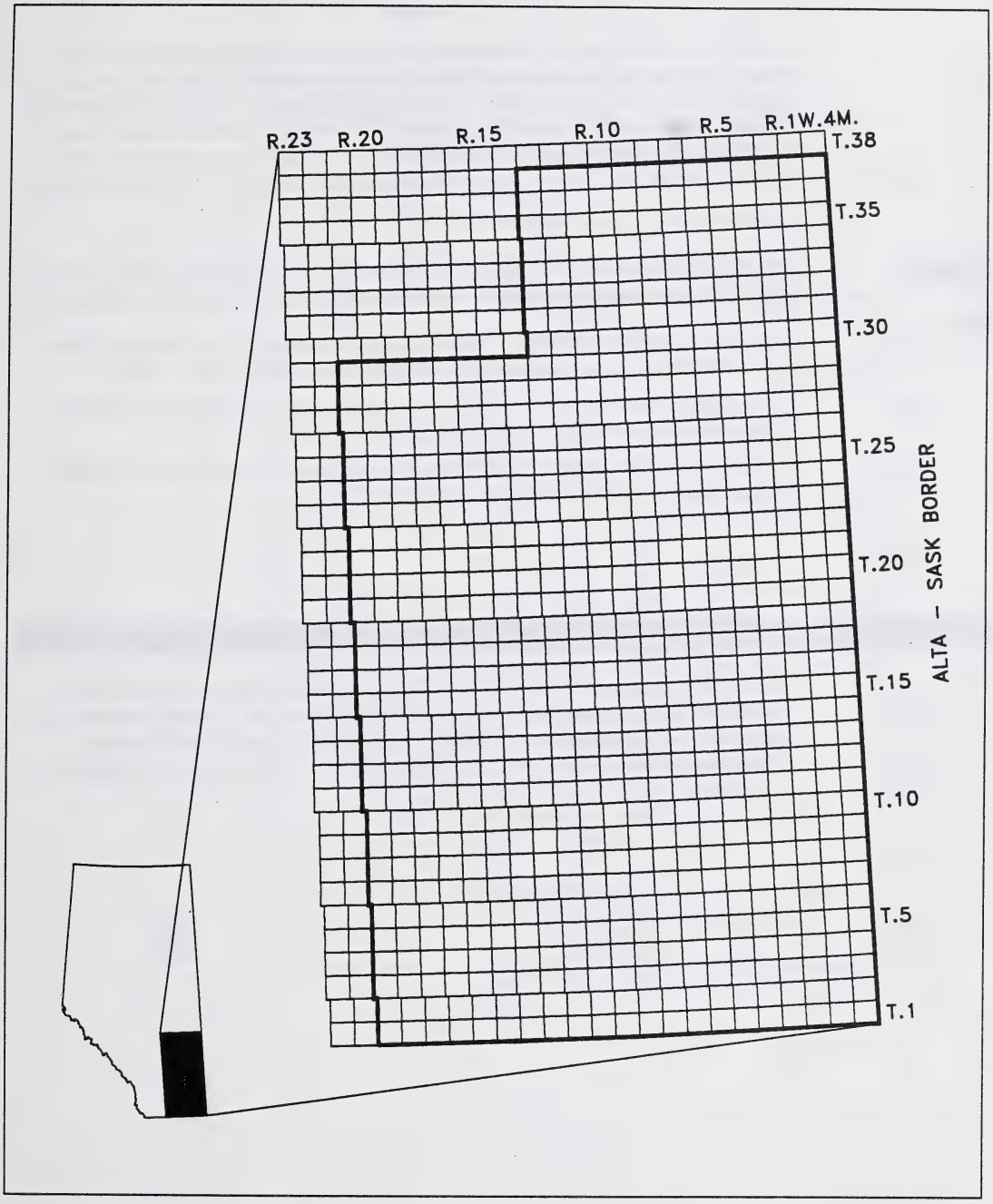

FIGURE 2 – AREA WHERE SURFACE CASING IS WAIVED FOR WELLS DRILLED TO THE BASE OF THE WHITE SPECKS

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In areas prone to drilling problems associated with unconsolidated zones near the surface, you must set the conductor below the unconsolidates. If you are planning a program of wells in a certain area, it is good drilling practice to drill a slim pilot hole to detect the base of the unconsolidates in the first well and to ream a larger hole to this depth before setting casing. You must meet the equipment spacing requirements set out in the *Oil and Gas Conservation Regulations*, Section 8.135, Subsection 9(b).

Oil Sands Core Holes and Oil Sands Evaluation Wells

EUB *ID 89-2* (see Appendix 4) lists blowout prevention and drilling requirements for core holes and oil sands evaluation wells in surface mineable oil sands areas (Figure 3).

- Within the surface mineable oil sands area, surface casing is not required if you set conductor pipe into a competent formation and install a Class 1 BOP.
- You may follow the same requirements within 10 km of the surface mineable oil sands area if the well does not exceed 200 m in depth.
- These requirements apply to core holes and oil sands evaluation wells only. They do **not** apply to conventional wells within Figure 2.

1.2 Surface Casing Waivers—Approval Required

To obtain an exemption from surface casing, you must indicate on Schedule 4 of *Guide 56* that the requirements of *Guide 8* are not met and file your application as non-routine. You must also attach to your application a detailed explanation including the items listed in *Guide 56,* Appendix 1, "Wells: Technical Guidelines," pages 10-11.

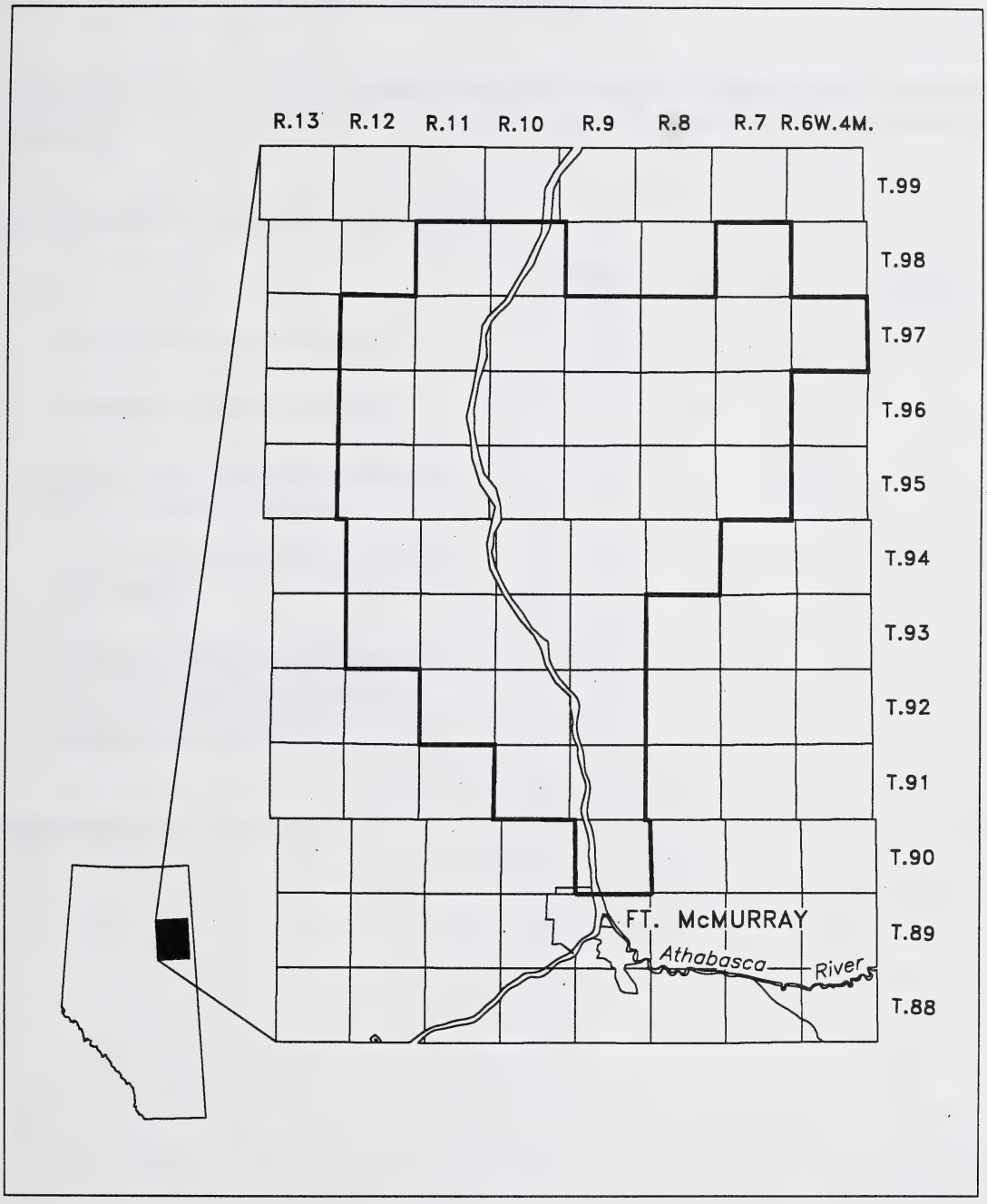

FIGURE 3 – SURFACE MINEABLE OIL SANDS AREA

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Feedback Form—Surface Casing Waivers

*The EUB welcomes your comments on the **Surface Casing Waiver Guide**. Your responses will be considered when the guide is updated. You may send this form in any time. Duplicate the form for repeated use. Thank you for your time and consideration.*

Please circle your response, using the following scale:

		Strongly Agree	Agree	Disagree	Strongly Disagree
1.	I found the language in the guide clear.	1	2	3	4
2.	I found the instructions easy to follow.	1	2	3	4
3.	I found it easy to tell what the requirements were for a surface casing waiver.	1	2	3	4
4.	I found it easy to decide if I required EUB pre-approval.	1	2	3	4
5.	I found it clear that I had to use documents in the Appendices to be fully aware of all the regulations and requirements that apply to surface casing.	1	2	3	4

Additional suggestions and comments:

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Section 2

Surface Casing Standards

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Surface Casing Check Sheet

Special Areas: If well is in the Senex, Kidney, Trout, or associated area, or in the specific high-hazard area (southeastern Alberta) or is being drilled for the purpose of waste disposal, see *Guide 8*, Section 2.1.

I: NORMAL SURFACE CASING REQUIRED (*GUIDE 8*, SECTION 2.2)

1. Maximum of the most representative pressure measurements in area: _____ kPa

2. Depth of recorder: _____ (m)

3. Reference well: _____/_____-_____-_____-_____-_____ W_____

	YES	NO
4. Higher pressures were found but were discounted.	☐	☐

Reason: _____

5. Maximum gradient: (1) ÷ (2) = _____ kPa/m

6. Surface casing depth required:

$$\frac{\text{Maximum gradient} \times \text{TVD} \times (0.5 - 0.0000625\ \text{TVD})}{22} = \text{_____ m}$$

7. If (6) is less than 10% TVD, use 10% TVD = _____ m

II: SURFACE CASING REDUCTION (*GUIDE 8*, SECTION 2.3)

TYPE 1 Reduction

Normal surface casing depth required: _____ m (6 or 7 above)

Reduced surface casing depth (6 or 7 above) x 0.913 = _____ m

One of the requirements will be followed:

	YES	NO
1. A PVT system will be installed with a probe in each active mud compartment; system is sensitive to ±1.0 m^3 and will alarm at ±2.0 m^3.	☐	☐
or		
2. A leak-off test will be conducted according to the procedure outlined in Appendix 2.	☐	☐

TYPE 2 Reduction

Normal surface casing depth required: _____ m (6 or 7 above)

Reduced surface casing depth (6 or 7 above) x 0.707 = _____ m

Three of the requirements will be followed:

	YES	NO
1. The well is in a development-type setting.	☐	☐
2. The well is low risk.		
• The field kick rate is less than 3 per 100 development wells.	☐	☐
or		
• The field kick rate is less than 3 per 100 development wells drilled in the field to a formation not exceeding the terminating formation of this well.	☐	☐
3. A PVT system will be installed with a probe in each active mud compartment; the system is sensitive to ± 0.5 m^3 and will alarm at ± 1.0 m^3.	☐	☐
4. A leak-off test will be conducted in accordance with Appendix 2.	☐	☐

(continued on next page)

TYPE 3 Reduction

Normal surface casing depth required: _____ m (6 or 7 above)

Historical surface casing depth required: _____ m

The historical depth requested is the same or greater than that set in the following wells:

WELL LOCATION	TOTAL DEPTH (m)	SURFACE CASING (m)	YEAR

The *five* requirements will be followed:

	YES	NO
1. The well is in a development-type setting.	☐	☐
2. The well is low risk.		
• The field kick rate is less than 3 per 100 development wells.	☐	☐
or		
• The field kick rate is less than 3 per 100 development wells drilled in the field to a formation not exceeding the terminating formation of this well.	☐	☐
3. A PVT system will be installed with a probe in each active mud compartment; the system is sensitive to ± 0.5 m^3 and will alarm at ± 1.0 m^3.	☐	☐
4. A leak-off test will be conducted in accordance with Appendix 2.	☐	☐
5. An emergency flare line will be installed in accordance with Figure 7.	☐	☐

TYPE 4 Reduction

Normal surface casing depth required: _____ m (6 or 7 above)

"Prognosed" top of problem zone: _____ m

Name of problem zone: _____

Surface casing depth requested: _____ m

Reason zone is a problem: _____

The *three* requirements will be followed:

	YES	NO
1. A PVT system will be installed with a probe in each active mud compartment; the system is sensitive to ± 0.5 m^3 and will alarm at ± 1.0 m^3.	☐	☐
2. A leak-off test will be conducted in according to the procedure outlined in Appendix 2.	☐	☐
3. An emergency flare line will be installed in accordance with Figure 7.	☐	☐

Section 2: Surface Casing Standards

TOPIC	DESCRIPTION
2.0 Before You Begin	
Step 1	If the proposed well(s) fall within a special area outlined in Section 2.1, you must set surface casing to the specified depth. EUB pre-approval is **not** required.
Step 2	Determine the surface casing setting depth of the proposed well(s) by using the Surface Casing Check Sheet, discussed in Section 2.2. EUB pre-approval is **not** required.
Step 3	If the proposed well(s) fall outside a special area, you may reduce the minimum surface casing setting depth provided that you drill with well control enhancements discussed in Section 2.3. EUB pre-approval is **not** required.
2.1 Special Areas	
	If the proposed well(s) are in the Senex, Kidney, Trout, or associated areas or in the specific high-hazard area of southeastern Alberta or if they are being drilled for the purpose of waste disposal, the surface casing must be set at the minimum requirements stipulated. This does **not** require pre-approval.
Senex, Kidney, Trout, and Associated Areas	Surface casing for the Senex, Kidney, Trout, and associated areas (see Figure 4) must be set at or near the top of the Upper Devonian, according to good drilling practice, to ensure proper isolation of the Lower Cretaceous from groundwater reserves, as stated in EUB *ID 91-6*. This is significantly deeper than the casing depth required in Section 2.1 of this guide. When drilling a surface hole in this area, you must have the conductor pipe set to a depth of 20 m and install a diverter system. See *ID 91-6* (Appendix 4) for additional requirements.
Specific High-Hazard Area of Southeastern Alberta	EUB *ID 92-1* (Appendix 4) defines the area within townships 19-24, ranges 5-10, west of the 4th meridian, as a high-hazard area for wells penetrating the Mannville zone. *ID 92-1* specifies that the minimum surface casing setting depth within this area is 180 m. Therefore, if the calculation or determination of surface casing using *Guide 8* is less than 180 m, the required depth remains 180 m, as specified in *ID 92-1* (see Figure 5).
Waste Disposal Wells	Class Ia waste disposal wells must have surface casing set 25 m below the base of the deepest usable aquifer. For further information, refer to EUB *Guide 51* (see Appendix 3).

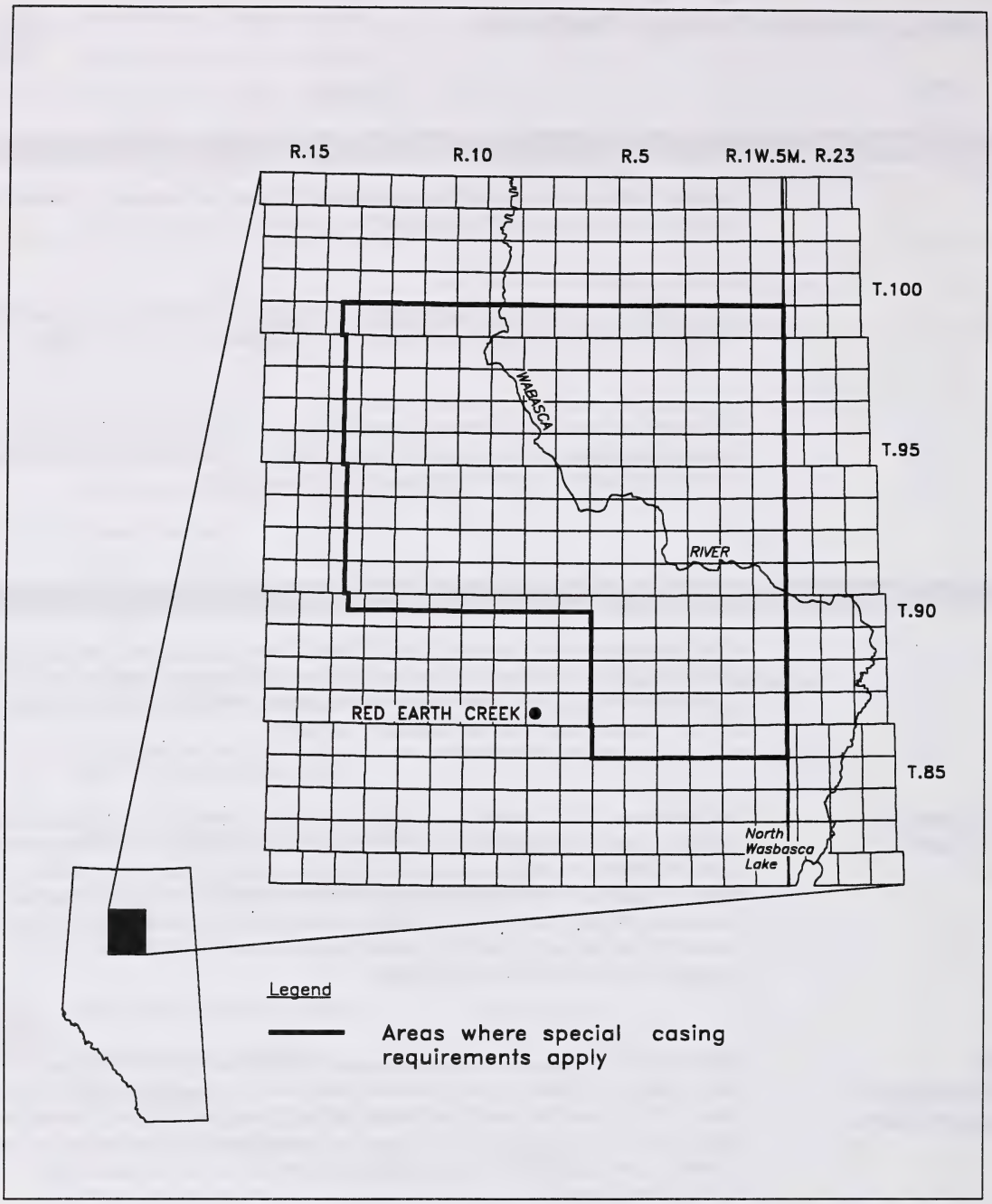

FIGURE 4 – SENEX, KIDNEY, TROUT, AND ASSOCIATED AREAS

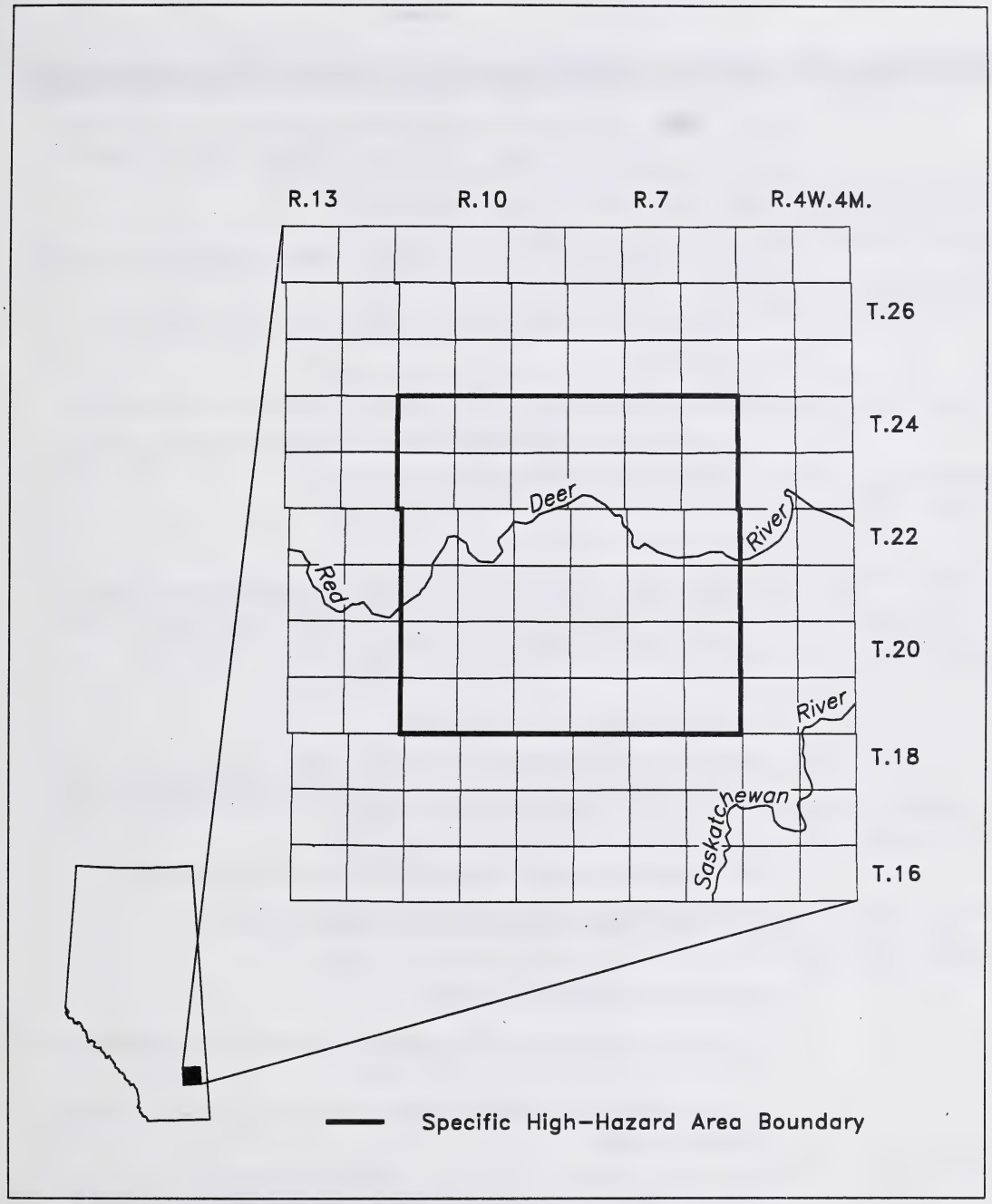

FIGURE 5 – SPECIFIC HIGH–HAZARD AREA OF SOUTHERN ALBERTA

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2.2 Completing the Surface Casing Check Sheet—Section I: Normal Surface Casing Required

Complete the Surface Casing Check Sheet, Section I, to decide the surface casing setting depth. This does **not** require EUB approval. However, if the well is selected for audit, you must submit the Surface Casing Check Sheet.

1. What is the maximum of the most representative pressure measurements (kPa) in the area?
   - Use the maximum pressure that you would encounter while drilling the proposed well.
   - For a description of representative pressure measurements, see Appendix 1.
   - If the well is in an undeveloped setting where there is insufficient pressure data, see number (5), below.

2. Provide the depth of the recorder (m).
   - Determine the depth of the maximum most representative pressure using one of the following sources, listed in the EUB's order of preference: DST, AOF, Build-up, Static Gradient, or AWS. (See Appendix 1 for definitions.)

3. Provide the location of the reference well.
   - This is usually the most representative well within a 5 km search area. However, you might decide on a more suitable search area for geological reasons.

4. Were higher pressures found in the area but discounted? If yes, state why.
   - Keep supporting technical information on file in case of audit.

5. Provide the maximum gradient (kPa/m).
   - Calculate the maximum gradient using the maximum pressure measurement in the area divided by the depth of the recorder.
   - Use offset well data, as required by EUB *ID 92-1* (see Appendix 4), to decide pressure gradients.
   - If a well is in an undeveloped setting where there is insufficient pressure data, use the 10 kPa/m curve (see Figure 6, Determination of Standard Surface Casing Setting Depth) or use 10 kPa/m in the equation.

6. Calculate the surface casing depth required (m).
   - Using the maximum gradient from (5), calculate the surface casing required and enter the result on line 6.

$$\text{Depth} = \frac{\text{Maximum gradient} \times \text{TDV} \times (0.5 - 0.0000625\,\text{TDV})}{22}$$

- There might be instances where it is technically correct to use the maximum pressure instead of the maximum pressure gradient multiplied by planned true vertical depth. To calculate the maximum bottom-hole pressure, see Appendix 1.

  In case of audit, you must support the use of maximum pressure in the calculation with a technical reason why the resulting surface casing setting depth is significantly affected.

- Wherever a well is drilled near a steep valley break, the well design, including surface casing setting depth, must prevent breakthrough to the valley wall during drilling operations.

- If the planned surface casing setting depth is reached in an unconsolidated formation, drilling should continue until a competent formation is penetrated by at least 5 m.

- The amount of surface casing required does not allow a well to be shut in indefinitely (i.e., the maximum shut-in period is 15 minutes to obtain shut-in pressures). The intent of the shut-in period is to allow implementation of acceptable methods of well control, provided the surface casing is set in a competent formation.

7. If the calculation in (6) is less than 10% of TVD, use 10% of TVD.

   - The minimum surface casing to be set is 10 % of true vertical depth, regardless of the pressure expected to be encountered (unless surface casing is waived or reduced).

     For shallow wells where the well will terminate no more than 15 m below the **first** hydrocarbon formation encountered, you may use the surface casing depth based on the maximum pressure gradient of that zone; the value does not have to be increased to 10% of TVD.

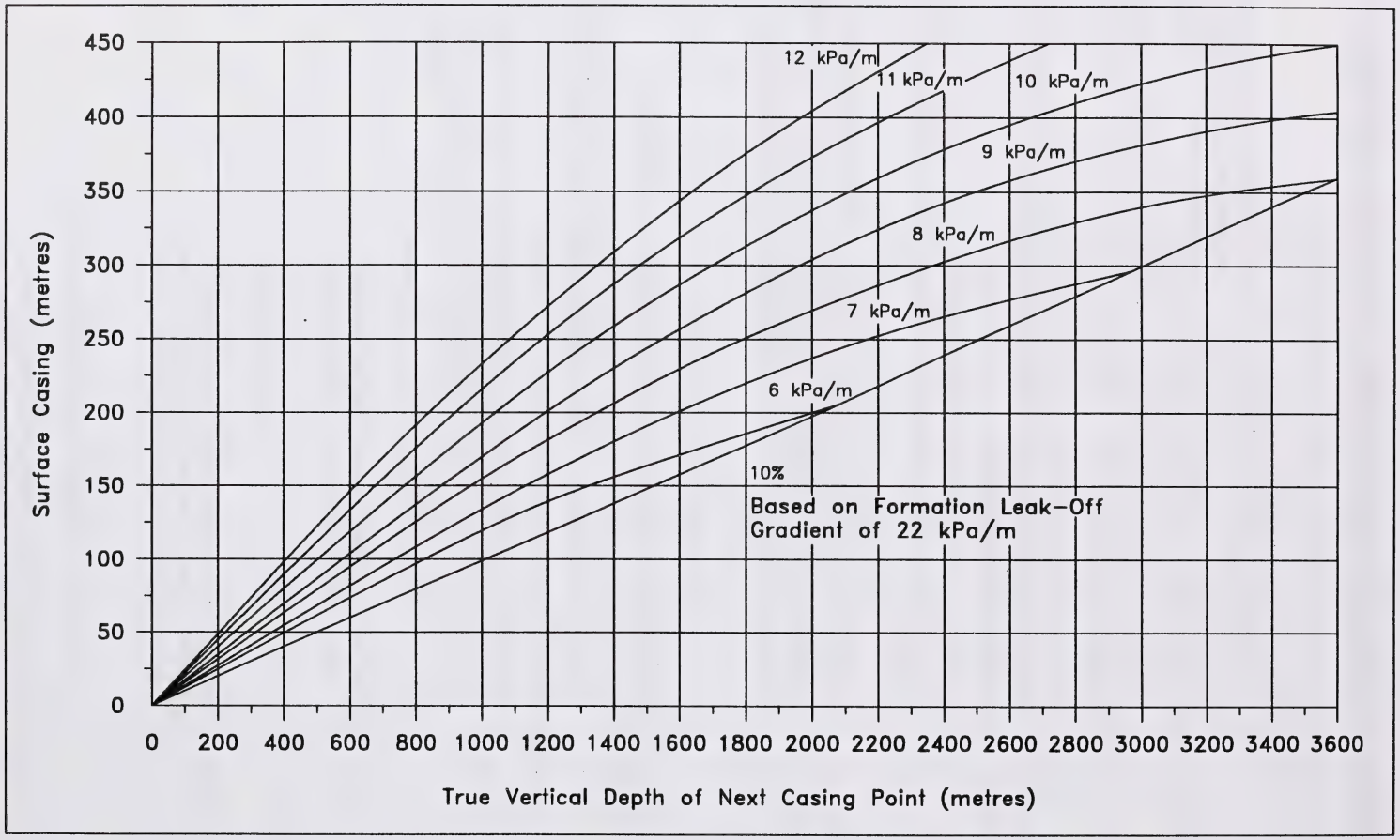


FIGURE 6 – DETERMINATION OF STANDARD SURFACE CASING SETTING DEPTH

2.3 Completing the Surface Casing Check Sheet—Section II: Surface Casing Reduction

Complete the Surface Casing Check Sheet, Section II, to determine the surface casing reduction depth. This does not require EUB approval. However, if the well is selected for audit, you must submit the Surface Casing Check Sheet.

Surface casing reductions are available for low-risk wells in a development-type setting (except type 1 below). The basis for the four-tier reduction system detailed below (types 1-4) is to ensure that well control will not be compromised by the reduction of surface casing depth.

You may not apply any of these types of reduction to wells drilled in the high-hazard area of southeastern Alberta penetrating the Mannville zone.

Type 1—Reduction Factor for Wells Drilled with Well Control Enhancements

- Normal surface casing depth required (m).

  Enter the required surface casing setting depth or 10% TVD, whichever is greater, from Section I (6 or 7) of the Surface Casing Check Sheet.

- Reduced surface casing depth.

  Multiply the normal surface casing depth required by a reduction factor of 0.913.

  You may reduce the surface casing to this depth if **one** of the two well control enhancements listed will be followed. Show which of the two methods you will use by checking YES or NO next to each.

  1. Will you install a PVT system sensitive to ± 1.0 m^3 that will alarm at ± 2.0 m^3, with a probe in each active mud compartment?

     This assumes that the initial kick volume can be limited to 2.5 m^3 if the alarm is preset to sound at ±2.0 m^3.

     For an explanation of the PVT system, see Appendix 1.

  or,

  2. Will you have a leak-off test conducted in accordance with the procedure outlined in Appendix 2?

     If so, conduct a leak-off test at the surface casing shoe and use it to decide the maximum allowable casing pressure.

Type 2—Reduction for Low-Risk Development Wells

- Normal surface casing depth required (m).

  Enter the required surface casing setting depth or 10% TVD, whichever is greater, from Section I (6 or 7) of the Surface Casing Check Sheet.

- Reduced surface casing depth (m).

  Multiply the normal surface casing depth required by a reduction factor of 0.707.

You may reduce the surface casing to this depth if **three** of the four well control enhancements listed will be followed. Show which three methods you will use by checking YES or NO next to each.

1. Is the well in a development-type setting?

   For a definition of a development-type setting, see Appendix 1.

   In case of audit, you must provide offset wells and depths within a 5 km radius.

2. Is the well low risk?

   Ensure the well is low risk by its having either a field kick rate of less than 3 per 100 development wells drilled (see *Statistical Series 45: Listing of Percentage of Kicks*, Appendix 3) or a field kick rate of less than 3 per 100 development wells drilled in the field to a formation not exceeding the terminating formation of the proposed well. You must carry out this research.

3. Will you install a PVT system accurate to ±0.5 m^3 and sounding an alarm at ±1.0 m^3, with a probe in every active mud compartment?

   This assumes that the initial kick volume can be limited to 1.5 m^3 if the alarm is preset to sound at ±1.0 m^3.

   This reduction factor is only allowed for low-risk development wells, because it results in a 30% reduction in casing.

4. Will you have a leak-off test conducted according to the procedure outlined in Appendix 2?

   If so, conduct a leak-off test at the surface casing shoe and use it to decide the maximum allowable casing pressure.

Type 3—Reduction to Historical Setting Depth

- Normal surface casing depth required (m).

  Enter the required surface casing setting depth or 10% TVD, whichever is greater, from Section I (6 or 7) of the Surface Casing Check Sheet.

- Historical surface casing depth required (m).

  For wells drilled in older developed areas, you may reduce surface casing to not less than the typical setting depth in the area. For background information on historical setting depths, see Appendix 1.

  List the wells where surface casing was set to the applied-for depth on the table. You must have this list available in case of audit.

The surface casing may be reduced to the historical depth if all **five** of the well control enhancements listed will be followed. Show which methods you will use by checking YES or NO next to each.

1. Is the well in a development-type setting?

   For a definition of a development-type setting, see Appendix 1.

   In case of audit, you must provide offset wells and depths within a 5 km radius.

2. Is the well low risk?

   Ensure the well is low risk by its having either a field kick rate of less than 3 per 100 development wells drilled (see *Statistical Series 45: Listing of Percentage of Kicks*, Appendix 3) or a field kick rate of less than 3 per 100 development wells drilled in the field to a formation not exceeding the terminating formation of the proposed well. You must carry out this research.

3. Will you install a PVT system accurate to ±0.5 m^3 and sounding an alarm at ±1.0 m^3, with a probe in every active mud compartment?

   This assumes that the initial kick volume can be limited to 1.5 m^3 if the alarm is preset to sound at 1.0 m^3.

4. Will you conduct a leak-off test according to the procedure outlined in Appendix 2?

   If so, conduct a leak-off test at the surface casing shoe and use it to decide the maximum allowable casing pressure.

5. Will you install an emergency flare line in accordance with Figure 7?

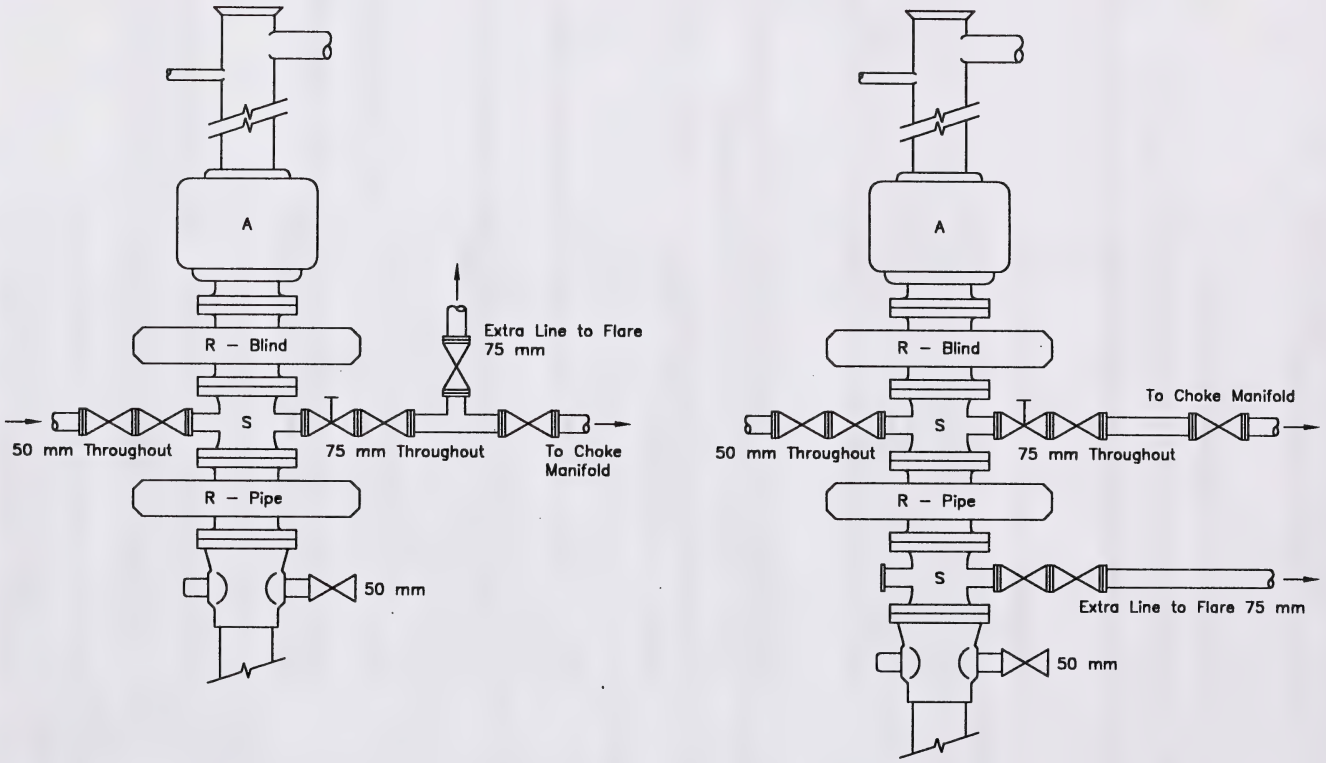
   This line shall be installed upstream of any fluid turns or high-pressure flexible hoses and shall extend directly to the flare pit.

Type 4—Reduction to a Depth Above a Problem Zone

A type-4 reduction is suitable for wells drilled in areas where it is necessary to set surface casing above a problem zone, such as in the Milk River area in southeastern Alberta, for the purposes of obtaining a high-quality cement job on the surface casing.

- Normal surface casing depth required (m).

  Enter the required surface casing setting depth or 10% TVD, whichever is greater, from Section I (6 or 7) of the Surface Casing Check Sheet.



Acceptable configurations for tie–in of emergency flare line (Type 3 and Type 4 Reductions)

FIGURE 7 – EMERGENCY FLARE–LINE CONFIGURATION FOR TYPE–3 AND TYPE–4 REDUCTIONS

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- "Prognosed" top of problem zone (m).

  Obtain the "prognosed" top of the problem zone from offset information and/or geological data.

- Name of problem zone.

- Surface casing depth requested (m).

  This depth should be not more than 15 m above the "prognosed" top of a zone known to be a problem in the area.

- Reason the zone is a problem.

  State what formation problems the evaluation of offset data shows, such as over-pressuring or lost circulation.

You may reduce the surface casing to a depth just above the problem zone if all **three** well control enhancements listed will be followed. Indicate which you will do by checking YES or NO next to each.

1. Will you install a PVT system accurate to $\pm 0.5\ m^3$ and sounding an alarm at $\pm 1.0\ m^3$, with a probe in every active mud compartment?

   This assumes that the initial kick volume can be limited to $1.5\ m^3$ if the alarm is preset to sound at $1.0\ m^3$.

2. Will you conduct a leak-off test according to the procedure outlined in Appendix 2?

   Conduct a leak-off test at the surface casing shoe and use it to decide maximum allowable casing pressure.

3. Will you install an emergency flare line in accordance with Figure 7?

   This line shall be installed upstream of any fluid turns or high-pressure flexible hoses and shall extend directly to the flare pit.

Feedback Form—Surface Casing Standards

*The EUB welcomes your comments on the **Surface Casing Standards Guide.** Your responses will be considered when the guide is updated. You may send this form in any time. Duplicate the form for repeated use. Thank you for your time and consideration.*

Please circle your response, using the following scale:

		Strongly Agree	Agree	Disagree	Strongly Disagree
1.	I found the language in the guide clear.	1	2	3	4
2.	I found the instructions easy to follow.	1	2	3	4
3.	I found the Surface Casing Check Sheet easy to use.	1	2	3	4
4.	I found it easy to calculate a surface casing setting depth and a surface casing reduction.	1	2	3	4
5.	I found it clear that I had to use documents in the Appendices to be fully aware of all the regulations and requirements that apply to surface casing.	1	2	3	4

Additional suggestions and comments:

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Section 3

Conductor Casing Standards

Section 3: Conductor Casing Standards

TOPIC	DESCRIPTION
Running Conductor Casing	If the surface hole is shallower than 450 m, conductor casing is **not** required and EUB pre-approval is **not** required. The EUB requires that you run conductor casing and a Class I BOP for surface holes deeper than 450 m when hydrocarbon-bearing formations are present in the surface hole. If hydrocarbon-bearing zones are absent, you may drill without conductor casing and do not require approval.

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Appendices

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Appendix 1

Definitions and Background Information

Introduction

TOPIC	DESCRIPTION
The Two Main Purposes for Surface Casing	**Well control:** Surface casing is an integral part of the well control system. *Guide 8* outlines the minimum surface casing setting depth requirements under the *Oil and Gas Conservation Regulations*, Section 6.080. EUB surface casing requirements do not allow extended shut-in periods during well control operations. However, these requirements do allow controlling a well by an acceptable method, such as the Drillers Method or the Low Choke Method (see *First Line Supervisor's Blowout Prevention*, Appendix 3), if the surface casing is set in a competent formation, i.e., one that displays a leak-off gradient of at least 22 kPa/m. **Protection of groundwater reserves containing a usable water resource:** Usable aquifers (water containing less than 4000 mg/l total dissolved solids) must be covered by cementing surface casing, cementing the next casing string, or appropriate placement of open-hole abandonment plugs. Licensees may choose the most effective means when designing wells. For information regarding the depth of usable water aquifers in the province, refer to *Statistical Series 55: Alberta's Usable Groundwater Base of Groundwater Protection Information* (see Appendix 3).

Definitions

Surface Casing	Surface casing is the first string of casing (after conductor pipe) that is set in a well.
Waiver of Surface Casing	Waiver of surface casing means that you are not required to run any surface casing but you may use conductor casing (a minimum of 20 m) to drill a well to total depth.
Conductor Casing	Conductor casing is a short string of large-diameter casing used to keep the wellbore open and to provide a means of conveying the drilling fluid flowing up from the wellbore to the mud pit.
Development-Type Setting	A development-type setting is one that has a minimum of three offset wells each in a different direction from the proposed location within 1.5 km of each other. The offset wells must be drilled to the same formation, or deeper, than the proposed well(s).

Background Information for Section 2.1

Representative Pressure Measurements

To obtain representative pressure measurements when drilling outside known pools, use the maximum drill-stem test pressures in the area; when drilling inside the geological bounds of a known pool, use current bottom-hole pressure measurements, especially for pools subject to enhanced recovery or pools depleted through extensive production. Wherever you choose to use depleted pressures to calculate surface casing setting depth, you must have supporting geological information available in case of audit to confirm that the subject well will be within the geological bounds of the pool in question.

Methods of Determining Maximum Pressures

- Drill-Stem Test (DST)—The conventional method of formation testing
- Absolute Open Flow Potential (AOF)—The maximum flow rate that a well could theoretically deliver with zero pressure at the face of the reservoir
- Build-up—A test in which a well is shut in for a prescribed period and a bottom-hole pressure bomb run in the well to record the pressure
- Static Gradient (Stat. Grad.)—The pressure exerted by a fluid upon a surface that is at rest in relation to the fluid
- Acoustic Well Sounder Survey (AWS)—A well-logging method in which sound impulses are generated and transmitted into the formations opposite the wellbore

Calculating Maximum Bottom-hole Pressure

To decide the minimum surface casing requirements, it is assumed that the surface casing shoe will withhold a predetermined percentage of the maximum bottom-hole pressure. That percentage varies with the planned true vertical depth of the well.

The required percentage of maximum bottom-hole pressure to be held at the surface casing shoe (Figure 8) is based on the following:

- First end-point—At zero well depth, the surface casing seat must withhold 50% of the bottom-hole pressure.
- Second end-point—At the maximum well depth of 3600 m with 450 m of surface casing, a 10 kPa/m formation pressure gradient and 22 kPa/m leak-off gradient are assumed in calculating that the surface casing seat must withhold 27.5% of the bottom-hole pressure.
- The assumed leak-off gradient of 22 kPa/m was chosen based on research of data from Alberta. Where actual leak-off gradients are less than 22 kPa/m, operators must be aware of the lower figure and use it in the calculation of maximum allowable casing pressure.

Where Max. grad.	=	maximum expected reservoir pressure gradient (kPa/m)
TVD	=	planned true vertical depth of well (m)

- Percentage of maximum bottom-hole pressure to be held at the surface casing shoe:

$$\% = 50 - 0.00625\ \text{TVD (m)}$$

- Maximum bottom-hole pressure (MBHP):

$$\text{MBHP} = \text{Max. grad. (kPa/m)} \times \text{TVD (m)}$$

There might be instances where it is technically correct to use the maximum pressure instead of the maximum pressure gradient multiplied by planned true vertical depth. In case of audit, you must support the use of maximum pressure in the calculation with a technical reason why the resulting surface casing setting depth is significantly affected.

- Pressure to be held at the surface casing shoe:

$$\text{Pressure to be held} = \text{MBHP} \times \text{percentage}/100$$

- Surface casing setting depth:

$$\text{Depth} = \frac{\text{Pressure to be held (kPa)}}{22\ \text{kPa/m}}$$

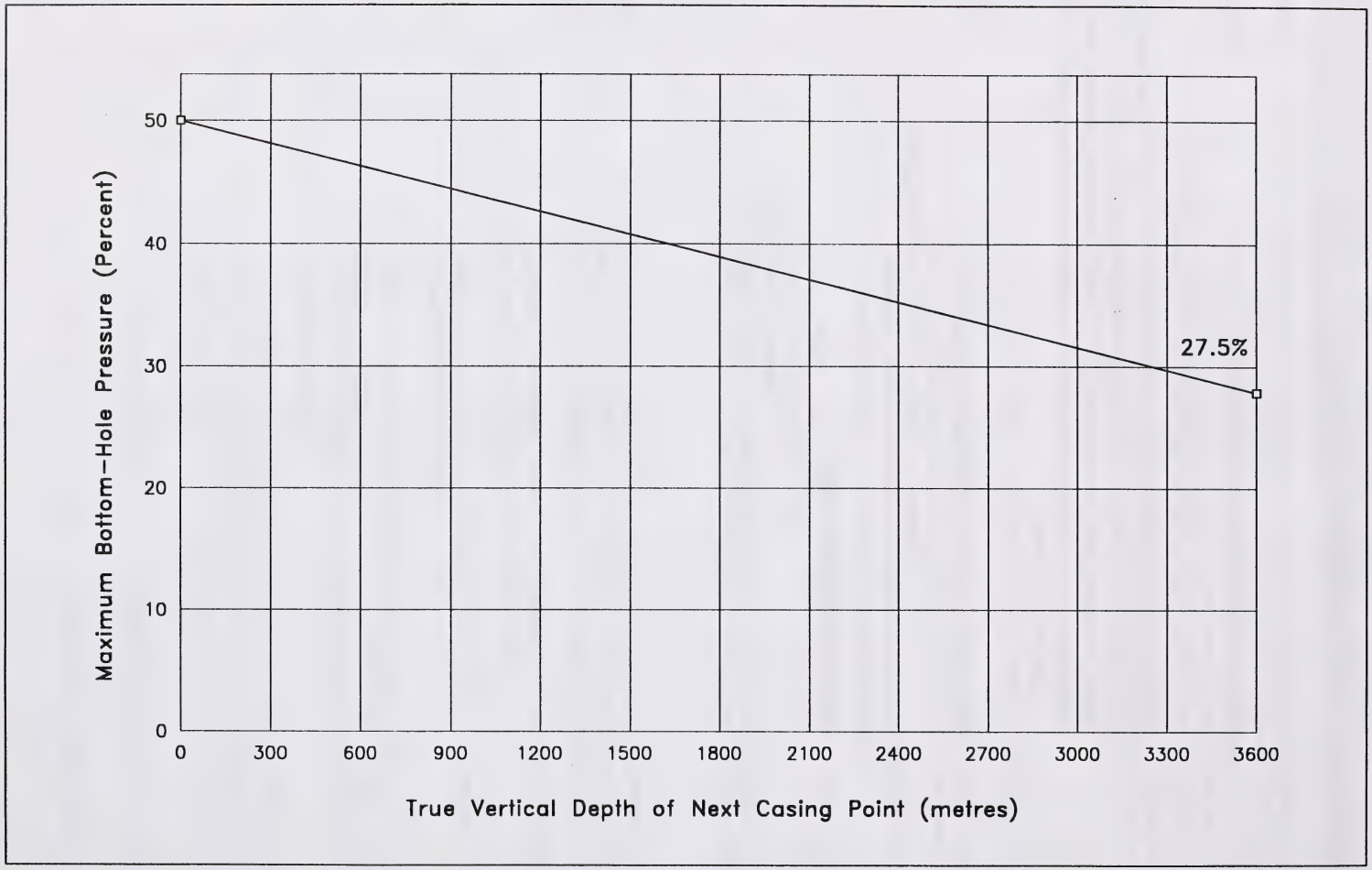

FIGURE 8 – PERCENTAGE OF MAXIMUM BOTTOM-HOLE PRESSURE TO BE AT SURFACE CASING SHOE

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Background Information for Section 2.3

PVT System for Type-1 Reduction

For wells drilled with a pit volume totalizer system (PVT) accurate to within ±1.0 m^3 and sounding an alarm at ±2.0 m^3, you may apply a general reduction factor to the surface casing decided in Section 2.1 of this guide. The PVT system must be installed with a probe in every active mud compartment.

Kick tolerance theory shows that surface casing required is proportional to the square root of the initial kick volume. The surface casing required by Figure 6 of this guide has been found sufficient for circulation of a 3.0 m^3 kick (assumed to be a maximum volume before well control action is initiated). Where you use PVT systems during drilling operations, it is reasonable to assume that initial kick volumes can be limited to 2.5 m^3 if the system is preset to sound an alarm at ±2.0 m^3.

$$\sqrt{2.5\ m^3/3.0\ m^3}$$

PVT System for Type-2 Reduction

For low-risk development wells drilled with a PVT system accurate to ±0.5 m^3 and sounding an alarm at ±1.0 m^3, you may apply the following reduction factor to the surface casing required by Section 2.1 of this guide:

$$\sqrt{1.5\ m^3/3.0\ m^3} = 0.707$$

This assumes that the initial kick volume can be limited to 1.5 m^3 if the alarm is preset to sound at 1.0 m^3.

Historical Setting Depth

Reduction to less than a type-2 reduction results in insufficient casing to control the well using the Drillers Method and thus requires use of the Low Choke Method (see *First Line Supervisor's Blowout Prevention*, Appendix 3).

If the setting depth is very shallow compared with total depth, you may need many circulations to circulate out a kick using the Low Choke Method. Due to the danger of a failure in the bleed-off system, you must use an emergency flare line for wells drilled with this type of casing reduction. In addition, you must meet all of the criteria for a type-2 reduction and carry out a leak-off test at the surface casing shoe to ensure more precise determination of the maximum allowable casing pressure.

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Appendix 2

Formation Leak-Off Tests

Conducting and Reporting Procedure

The integrity of the formation at the surface casing seat is a key factor during well control operations. You can accurately determine the maximum allowable casing pressure through testing the integrity at the surface seat. The Petroleum Industry Training Service encourages formation leak-off testing at all wells to ensure well control operations are conducted using the most representative information. The EUB strongly endorses the concept of leak-off testing at all wells due to variability of leak-off test results.

In addition, as specified in EUB *Guide 20*, bridge plugs may be used in leaking open-hole abandonments provided a leak-off test has been conducted (see *Guide 20* for additional requirements). There may be cost benefits for the licensee at the re-abandonment stage if a leak-off test was conducted during the initial drilling operation.

The recommended test procedure and reporting requirements for leak-off tests are: *

1. Use low-volume, high-pressure pump capable of pumping steadily and consistently at rates as low as 4L/minute.
2. Drill at least 5 m but not more than 10 m below surface casing shoe.
3. Pull up off bottom and fill hole.
4. Close blowout preventers; ensure system is free of leaks.
5. Start pumping slowly at a consistent rate of approximately 4-8 L/minute, depending on the setting depth of the casing.
6. Record pressure after each 4 L pumped, if possible.
7. Plot pressure against volume injected during the pumping, not afterwards (see Figure 9).
9. You must not use a rig mud pump for performing a formation leak-off test at the shoe of the surface casing.
10. Record results on a calculation sheet (see Formation Leak-Off Test sample form on page 13) and submit it to the EUB Operations Group within 30 days of rig release.

*Note: 1000 L = 1 m^3

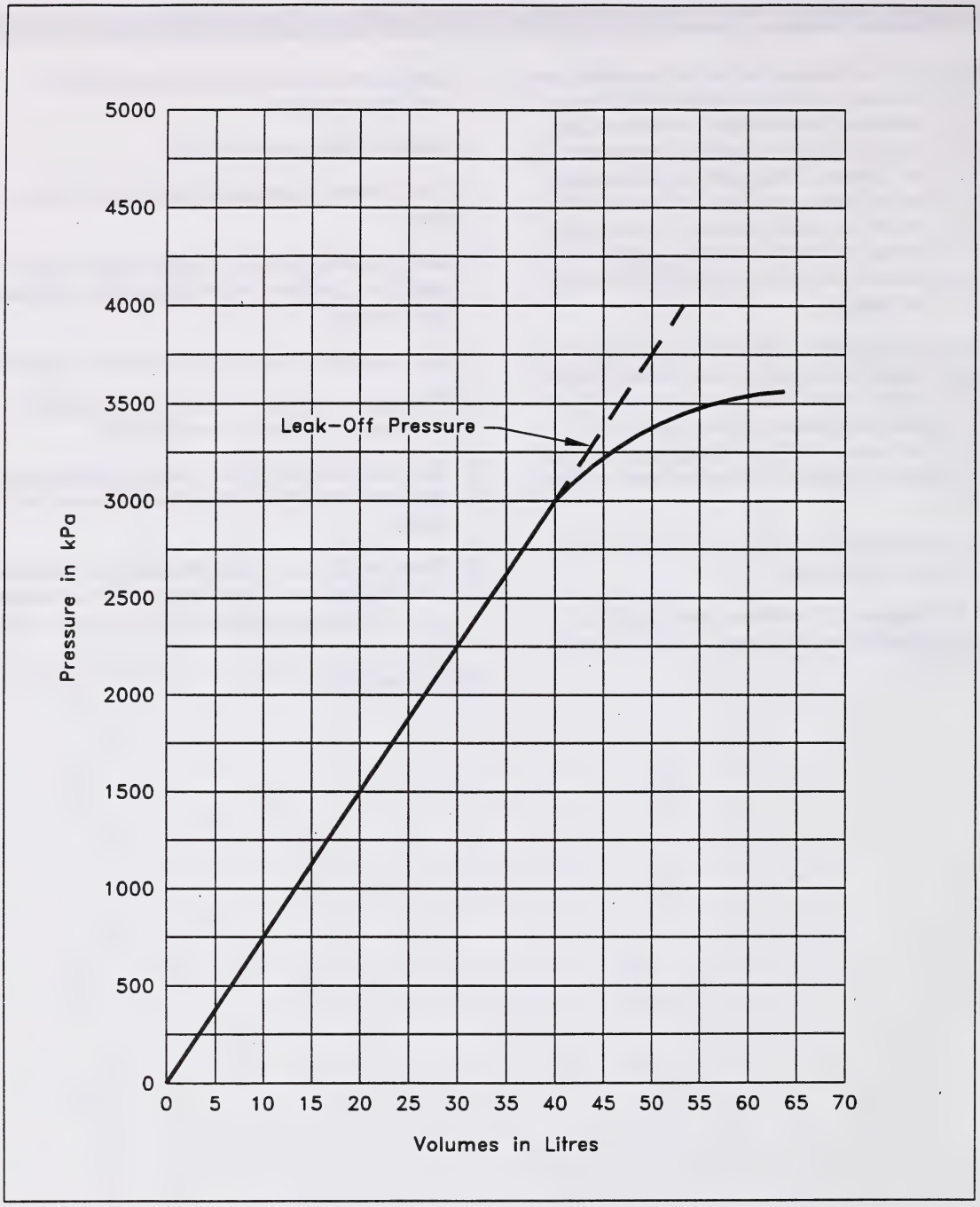

FIGURE 9 – PRESSURE vs. VOLUME PLOT

SAMPLE

EUB Alberta Energy and Utilities Board

Formation Leak-Off Test

Date: DAY MONTH YEAR

WELL NAME: _____

OPERATOR: _____

TESTING COMPANY: _____

TEST CONDUCTED BY (title): _____

SIZE OF PUMP AND PUMPING RATE: _____

TEST TAKEN TO LEAK-OFF: ☐ **YES** ☐ **NO** **IF NO, GIVE REASON(S):** _____

_____

1. Depth drilled out: _____ m
2. Surface casing setting depth: _____ m
3. Gradient of fluid in hole during test: _____ kPa/m
4. Hydrostatic pressure at casing shoe (2x3): _____ kPa
5. Leak-off pressure (surface): _____ kPa
6. Total pressure at shoe (4+5): _____ kPa
7. Leak-off pressure gradient (6÷2): _____ kPa/m

Projected total depth: _____ m

Depth of intermediate casing (if applicable): _____ m

Maximum BHP gradient expected: _____ kPa/m

Zone and depth where encountered: _____ m

Gradient of drilling fluid to be used when penetrating hydrocarbon-bearing strata: _____ kPa/m

SUBMIT A COPY OF LEAK-OFF TEST DATA, INCLUDING THE PRESSURE VS. VOLUME PLOT, TO:

Alberta Energy and Utilities Board
Operations Group, Facilities Division
640 5 Avenue S.W.
Calgary, Alberta T2P 3G4

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Appendix 3

References List

Material Cited in This Guide Is Available as Follows

From EUB Information Services (403-297-8190)

- *Guide 20: Well Abandonment Guide*
- *Guide 51: Injection and Disposal Wells*
- *Oil and Gas Conservation Act*
- *Oil and Gas Conservation Regulations*
- *Statistical Series 45: Listing of Percentage of Kicks in Development Wells by Field*
- *Statistical Series 55: Alberta's Usable Groundwater Base of Groundwater Protection Information*

From the EUB Library (403-297-8242)

- *Findings of the Committee on Surface Casing Requirements in the Lindbergh/Elk Point Area*

From the Petroleum Industry Training Service (P.I.T.S.) (403-250-9606)

- *First Line Supervisor's Blowout Prevention*, sections on Low Choke Method and Drillers Method

From CAPP Drilling and Completions Committee (403-267-1100)

- *Shallow Gas Flare Line Length Reduction*

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Appendix 4

EUB Interim Directives

1 September 1989

TO: All Oil Sands Operators and Drilling Contractors

BLOWOUT PREVENTION AND DRILLING PRACTICES FOR CORE HOLES AND OIL SANDS EVALUATION WELLS IN SURFACE MINEABLE AREAS

This Directive sets out the EUB's minimum requirements with respect to surface casing, and blowout prevention (BOP) practices and equipment for the drilling of oil sands core holes and evaluation wells (OV wells) within the Surface Mineable Areas. All existing special approvals for BOP requirements and/or surface casing within this area are superseded. The Surface Mineable Areas are defined by the attached map [Figure 3 in *Guide 8*].

Wells drilled within an approved mine area are exempt from the requirements of this interim directive in accordance with section 4(5) of the Oil Sands Conservation Regulations.

Drilling operations at all other wells must be carried out according to the following guidelines:

SURFACE MINEABLE AREAS

Inside the Surface Mineable Areas, wells are required to adhere to the following guidelines:

1 Conductor pipe must be set into a competent formation.

2 A system to divert gas a minimum of 15 metres away from the wellbore must be installed. All associated flare lines must be staked down.

3 The mud tank or pit must be located a minimum of 2 metres away from the wellbore and outside any enclosure around the wellbore.

4 When retrieving core or pulling pipe, the hole must be kept full of drilling mud at all times.

5 A stabbing valve or similar device to prevent flow up the inside of the drill string must be kept in a heated and accessible location at all times.

6 Wireline coring operations inside the drill pipe shall be conducted with equipment adequate to shut off any flow through the inside of the drill string.

7 During cold weather operation, sufficient heat shall be provided to ensure proper operation of the diverter system. This requirement shall be met consistent with Requirement No. 11 regarding flame-type equipment.

8 The diverter system shall be mechanically tested daily, and any equipment found defective shall be made serviceable before operations resume.

9 The licensee of a well shall, at all times, ensure that

a) the rig crew is trained in the operation of the diverter system; and

b) at least one person who has a valid Second Line Supervisor's Certificate in well control procedures, issued by the Petroleum Industry Training Service, is readily available.

10 All engines within 15 metres of the well must be equipped with shut-offs:

- air shut-offs for diesel engines; or
- electric shut-offs for gasoline engines.

11 No open fires, flame-type equipment, or other sources of ignition shall be allowed within 15 metres of the wellbore.

12 All enclosed areas such as core shacks, dog houses, etc, within 15 metres of the wellbore shall have two doors. These doors must open out from the wellbore.

13 Winter shrouding surrounding the wellbore must be left open at the top and bottom to prevent the accumulation of hazardous vapours.

OUTSIDE SURFACE MINEABLE AREAS

1 Wells not exceeding 200 metres in total depth, and within 10 kilometres of the Surface Mineable Areas, may conform to the same blowout prevention and drilling practices as inside the Surface Mineable Areas.

2 Wells deeper than 200 metres, must conform to the blowout prevention and drilling practices required by the Oil and Gas Conservation Regulations.

Further information regarding this interim directive may be obtained from EUB Information Services (403-297-8190).

DEFINITIONS

Surface Mineable Areas: An area specified by the Board as containing surface mineable reserves.

Oil Sands:

i) sands and other rock materials containing crude bitumen;

ii) the crude bitumen contained in those sands and other rock materials; and

iii) any other material substances, other than natural gas, in association with that crude bitumen or those sands and other rock minerals referred to in clauses (i) and (ii)

Crude Bitumen: A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well.

Oil Sands Evaluation Well (OV Well): A well which when being drilled is expected by the Board to penetrate a pool or oil sands deposit and which is drilled for the sole purpose of evaluation.

Diverter: A device used to divert the flow of hydrocarbons away from the immediate wellbore area.

Stabbing Valve/Inside Blowout Preventer: A device installed in the drill string to prevent flow up the inside of the drill string.

28 March 1991

To: All Oil and Gas Operators
All In Situ Oil Sands Operators
All Drilling and Servicing Contractors

This directive amends certain minimum regulatory requirements for

- the drilling and servicing of heavy oil/in situ oil sands wells,
- equipment and spacing in the production of heavy oil/in situ oil sands, and
- measurement and accounting for heavy oil/in situ oil sands.

Heavy oil, for the purpose of this directive, is a crude oil product with a density of 920 kg/m3 or greater at 150°C. This crude oil density incorporates most of the areas of east-central Alberta, Figure I, where heavy oil production operations are normally considered to occur.

Oil sands areas, Figure I, are defined in EUB Informational Letters IL 84-7 and IL 89-3.

These regulatory amendments are a result of the Board's review of the recommendations from the Operating Practices Steering Committee (OPSC) for Heavy Oil/Oil Sands Operations. The OPSC has also developed Alberta Recommended Practices (ARPs) for heavy oil/oil sands operations which will be available from the Petroleum Industry Training Service in April 1991. The Board recognizes that this directive to some extent overlaps the procedures and equipment outlined in the ARPs.

However, the Board considers it necessary to formally regulate those matters listed in this directive.

Unless exempted by this directive or EUB approval, heavy oil/oil sands operations shall be conducted in accordance with the Oil and Gas Conservation Regulations and the Oil Sands Conservation Regulations.

This directive is effective 1 April 1991.

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1.2 Drilling Blowout Prevention System
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Figure I - Oil Sands Areas [see *Guide 8*, Section 1, page 2]
Figure II - Drilling Blowout Prevention Systems for Heavy Oil and Oil Sands - Class IA
Figure III - Servicing Blowout Prevention Systems - Class IIA

1 DRILLING BLOWOUT PREVENTION REQUIREMENTS

1.1 General

The requirements listed below amend certain drilling blowout prevention requirements as listed in sections 8.130 through 8.143 and 8.149 of the Oil and Gas Conservation Regulations as they apply to the drilling of heavy oil and in situ oil sands wells.

A new Drilling Blowout Prevention System, Class IA, replaces BOP Class I for certain heavy oil/oil sands wells where an application for a reduction in conventional surface casing setting depth has been approved by the EUB.

Notwithstanding surface casing reduction for heavy oil/oil sands wells, wells that have the potential for significant lost circulation, hole sloughing, high gas deliverability rates or that may be influenced by a secondary recovery scheme must set surface casing and be drilled in accordance with the Oil and Gas Conservation Regulations with a minimum Class II BOP System.

The blowout prevention and drilling requirements for oil sands core holes and evaluation wells in surface-mineable areas are specified in EUB Interim Directive ID 89-2.

Requests for further information regarding drilling requirements for heavy oil/oil sands wells should be directed to the Drilling Section of the Board's Drilling and Production Department at 297-8186, or the applicable area office.

1.2 Drilling Blowout Prevention System

1.2.1 Class IA BOP System

A Class IA drilling BOP system shall conform to the following minimum requirements:

(1) Stack components as shown in Figure II.

(2) A minimum 152-mm full opening remotely activated valve and 152-mm bleed-off line. The length of the bleed-off line may be reduced to 25 m from 50 m if the line terminates in a flare tank.

(3) A daily function test shall be conducted on the annular preventer. The full opening valve shall be function-tested at least once per well. Pressure tests are not required.

1.3 Blowout Prevention Requirements

A Class IA BOP system shall be permitted for the drilling of crude oil or crude bitumen with a density of 920 kg/m3 or greater and where a reduction in conventional surface casing setting depth has been approved by the EUB.

2 SERVICING BLOWOUT PREVENTION REQUIREMENTS

2.1 General

The requirements listed below amend certain servicing blowout prevention requirements as listed in sections 8.144 through 8.148 of the Oil and Gas Conservation Regulations as they apply to the servicing of heavy oil and oil sands wells.

A new Servicing Blowout System, Class IIA, has been developed for heavy oil/oil sands wells to replace BOP Class I (heavy oil) where the expected bottom-hole pressure is less than 21 000 kPa and the expected H2S release rate will be less than 0.001 m^3/s. In addition, the criteria for well servicing BOP Class III for heavy oil/oil sands has been amended to a flow rate of 0.001 m^3/s H_2S from an H_2S concentration greater than 10 moles per kilomole.

The directive also recognizes the different servicing requirements for heavy oil/oil sands wells under primary vs. secondary recovery where

A. PRIMARY RECOVERY WELL, for the purpose of this directive, is defined as a well having a sandface reservoir pressure equal to or less than the hydrostatic pressure that would be exerted at the sandface if the well were filled with formation fluids, and

B. SECONDARY RECOVERY WELL (EOR), for the purpose of this directive, is defined as a well having a sandface reservoir pressure greater than that described above, by virtue of injection into the formation of fluid(s) other than water at ambient temperatures. This includes all wells that are a part of an active EOR project approved by the EUB and any offset wells within 1 km of an EOR well within the project.

Requests for further information regarding servicing requirements should be directed to the Servicing and Completions Section of the Board's Drilling and Production Department at 297- 3554, or the applicable area office.

2.2 Servicing Blowout Prevention System

A Class IIA servicing BOP system shall conform to the following minimum requirements:

(1) Stack components as shown in Figure III.

(2) Although a rig pump, tank or circulation manifold is not required during servicing operations, return fluids must be contained. If a rig tank is used it must be located a minimum of 15 m from the well.

(3) A 50-mm kill line connected to the wellhead, spool or BOP port and extending a minimum of 15 m from the well is required during the servicing of a secondary recovery well. A bleed-off and kill line is not required during the servicing of a primary recovery well.

2.3 Blowout Prevention Requirements

(1) The servicing of a heavy oil/oil sands well shall be conducted with

(a) Class IIA BOP equipment where the bottom hole or injection pressure is less than or equal to 21 000 kPa and the maximum potential H_2S release rate for the well is less than 0.001 m^3/s; or

(b) Class III BOP equipment as specified by Schedule 10 of the Oil and Gas Conservation Regulations where the bottom-hole or injection pressure exceeds 21 000 kPa or the maximum potential H_2S release rate is equal to or greater than 0.001 m^3/s.

(2) The BOP components shall be tested to the pressures specified in section 8.147 of the Oil and Gas Conservation Regulations. A 10-minute test shall be conducted prior to servicing the first well of a program, and

(a) thereafter, every 7 calendar days in a secondary recovery well servicing program or every 30 calendar days in a primary recovery well servicing program;

(b) in addition, before servicing each well in a secondary recovery well servicing program, each BOP component shall be tested for at least 2 minutes to the pressures referenced in Regulation 8.147.

(3) Bailing operations may be conducted to an open tank. The tank may be adjacent to the well but must be removed as soon as bailing operations are completed.

(4) A blowout preventer, capable of closing on the rod string, is required while tripping rods on secondary recovery wells. The preventer must be hydraulically operated with the control(s) located no closer to the well than the driller's control panel. Should the preventer be operated using service rig hydraulics, an alternative method to operate the preventer must be provided with the control(s) located a minimum of 7 m from the well.

3 PRODUCTION EQUIPMENT AND PROCEDURES

3.1 General

The requirements listed below amend certain production equipment requirements as listed in sections 7.060, 7.070, 8.030, 8.090 and 8.100 of the Oil and Gas Conservation Regulations as they pertain to production operations for heavy oil, and sections 6 and 7 of the Oil Sands Conservation Regulations for in situ oil sands operations. New requirements are specified for testing vent gas for H_2S from heavy oil/oil sands wells and facilities.

The criteria for establishing minimum requirements to produce sour gas at heavy oil/oil sands wells or batteries have been modified such that an H_2S release rate of 0.04 m^3/h is utilized instead of an H_2S concentration of 10 moles per kilomole.

Requests for further information regarding production operations should be directed to the Production Section of the Board's Drilling and Production Department at 297-8132, or the appropriate area office.

3.2 Hydrogen Sulphide (H2S) Requirements

Where heavy oil or oil sands is produced at a well or received at a battery:

(1) the licensee or operator shall test all vent gas for the presence of H2S as soon as possible but no later than 90 days of initial production and every third calendar year thereafter; and

(2) where H2S is present in the vent gas, the H2S release rate shall be determined each year using methods acceptable to the Board. The records of these determinations shall be made available to the Board upon request; and

(3) where the maximum potential H2S release rate is equal to or greater than 0.04 m3/h, the requirements of sections 7.060 and 7.070 of the Oil and Gas Conservation Regulations and sections 6 and 7 of the Oil Sands Conservation Regulations shall be complied with, except that

- the H2S may be burned in a minimum 4-metre flare stack or incinerator, or such greater height, required to ensure that ambient concentrations specified by Clean Air Regulations are not exceeded.

3.3 Fired Equipment and Engine Exhausts

The licensee or operator shall comply with sections 8.090 and 8.100 of the Oil and Gas Conservation Regulations, with the following exceptions:

(1) No open flame shall be permitted within 25 m of a heavy oil/oil sands well, storage tank or other source of ignitable vapour including Board-approved desand and ecology pits utilized for waste oil storage.

(2) No oil storage tanks, or desand and ecology pits, may be located within 25 m of a heavy oil/oil sands well unless approved by the Board or its authorized representative.

(3) Tank heaters are permitted in heavy oil/oil sands storage tanks to facilitate shipping of the product.

(4) An exhaust pipe from an internal combustion engine, located within 25 m of any heavy oil/oil sands well, shall be constructed such that the end terminates

(a) at least 1 metre from the wellhead, and directed away from the well. Where the exhaust pipe is used for heating it should be sloped to allow drainage of condensation,

(b) at least 1 m outside any engine enclosure.

(5) Diesel engines operating within 25 m of an oil sands/heavy oil well, process vessel or production storage tank must be equipped with an adequate air intake shut-off valve.

3.4 Prevention of Losses

(1) The area surrounding a tank or groups of tanks may be contoured to contain the volume of the largest tank in lieu of constructing a dike or firewall.

(2) Surface flow lines at single well facilities must be adequately marked or buried to prevent damage from equipment working on lease.

4 MEASUREMENT AND REPORTING REQUIREMENTS

4.1 General

The requirements listed below amend certain requirements as listed in sections 7.020, 7.030, 12.030, 12.150, 14.110 and 14.140 of the Oil and Gas Conservation Regulations and sections 15, 39, 40, 44 and 45 of the Oil Sands Conservation Regulations as they apply to both the measurement and reporting of production from heavy oil/oil sands wells.

The necessary amendments largely reflect a move away from conventional measurement and reporting at the well level and provides for some reduction in well measurement accuracy where conventional accuracy guidelines are not warranted. In recognition of the varying need for and accuracy of well-level production measurement and reporting in heavy oil operations, a system of classifying operational scenarios has been developed that makes provision for group or battery-level reporting. This system presents three classifications under which measurement and reporting needs are assessed having regard for royalty matters, working interest and offset equities, and engineering needs.

To summarize, a Class I scenario would be one in which royalty and equity concerns require accurate well-level measurement such that measurement and reporting requirements remain the same as for conventional oil production operations.

A Class II scenario would be one in which royalty concerns are low but production measurement and reporting is required for equity or engineering purposes. A reasonable degree of accuracy is therefore required but some latitude exists to provide for operational flexibility.

A Class III scenario represents one in which royalty, equity, and engineering concerns do not exist and production measurement and reporting can be performed on a group or facility basis to fit the operator's needs. Further details on the criterion for determining the classification are outlined in ARP 3.4.2.

The Board is prepared to approve measurement systems and procedures, reduced from conventional oil measurement requirements, under this classification system. Most impacted by the classification system are requirements for the level of production measurement and reporting (ie. well vs. group vs. battery) and well test frequencies. The determination of the classification is judgemental and requires agreement between the EUB and the operator.

Requests for further information regarding measurement and reporting requirements for heavy oil/oil sands wells should be directed to the Production Section of the Board's Drilling and Production Department at 297-8448 or 297-7232.

4.2 Testing of Wells in a Battery

The following minimum requirements amend section 7.030 of the Oil and Gas Conservation Regulations, specific to heavy oil/oil sands:

(1) Where a battery or group of wells receives flow lined heavy oil and the production is commingled before measurement, the operator of the battery shall test each well or group of wells in accordance with this section.

(2) The minimum duration of each well test shall be the lesser of 24 hours or the time required to obtain four consecutive data points which result in normalized test rates determined as follows:

(a) within 5 per cent of the mean of the four test rates, for total fluid production greater than 15 m^3/d, or

(b) within 10 per cent of the mean of the four test rates, for total fluid production less than 15 m^3/d.

(3) The minimum test frequency for all wells producing to a proration battery under primary production or waterflood operations shall be

(a) two tests per month where royalty or equity, and engineering concerns exist, or

(b) one test per month where accurate measurement is required solely for engineering purposes, but

(c) the licensee may be exempt from testing where it can be shown to the satisfaction of the Board that well test information is not needed for royalty, equity, or engineering purposes.

(4) The minimum test frequency for wells producing to a proration battery under thermal production shall be two tests per month; however,

(a) the licensee may be exempt from the requirement for such tests during periods of flowback where temperatures preclude testing, and

(b) the licensee may be exempt from testing where it can be shown to the satisfaction of the Board that well test information is not needed for royalty, equity, or engineering purposes.

4.3 Metering and Measurement of Gas

The following minimum requirements amend section 14.040 of the Oil and Gas Conservation Regulations, specific to heavy oil/oil sands wells:

Where heavy oil/oil sands is produced at a well, battery, or group of wells,

(1) the licensee of the well, battery, or group of wells shall accurately measure all gas produced in association with the heavy oil or oil sands with an approved gas meter;

(2) the licensee shall be exempt from subsection (1), subject to the condition that it supply to the Board satisfactory estimates of the volumes of the gas produced in accordance with subsections (3) and (4);

(3) within Designated Oil Sands Areas, associated gas production may be estimated, at the point of collection or emission, as follows:

(a) for single well batteries, gas production shall be estimated on the basis of an initial, representative, 24-hour GOR test performed on the well within 6 months of the on-production date. The GOR shall be updated on an annual basis if greater than 100 m^3/m^3, and every 3 years if less than 100 m^3/m^3;

(b) where associated gas from a number of wells is flow lined to a central point and total gas rates at the point of collection or emission are less than 2000 m^3/d, gas production shall be estimated on the basis of a group or battery GOR determined on an annual basis without allocation to individual wells;

(4) outside Designated Oil Sands Areas, associated gas production shall be determined for each well by representative 24-hour GOR tests where well gas production is less than or equal to 2000 m^3/d. The GOR tests shall be updated

(a) annually, where the total well gas rate is less than or equal to 500 m^3/d,

(b) semi-annually, where the total well gas rate is less than or equal to 1000 m^3/d and greater than 500 m^3/d, or

(c) monthly, where the total well gas rate is less than or equal to 2000 m^3/d and greater than 1000 m^3/d.

4.4 Measurement of Test Oil Production

The licensee or operator of a battery or group of wells shall comply with section 14.110 of the Oil and Gas Conservation Regulations, except

(1) a calibration or re-calibration required by subsection (1) or (3) of section 14.110 pertaining to initial calibration or annual re-calibration may be performed, on the meter only, in the shop using water as the calibration fluid, against a tank, master meter, or other approved method or device which will provide a meter factor, and

(2) calibrations shall be made using a documented calibration procedure.

4.5 Measurement of Water

The licensee or operator shall comply with section 14.140 of the Oil and Gas Conservation Regulations, except where a product analyser is used to determine water production, the licensee shall calibrate the instrument annually using a documented calibration procedure.

4.6 Release of Information

The Board shall make records, reports, or information available to the public in accordance with `section 12.150 of the Oil and Gas Conservation Regulations, except that the word "well" in subsection 2(d) shall be replaced by the phrase "well, battery, or group of wells" to provide for battery or group production reporting.

In addition, the Board shall make records, reports, or information available to the public in accordance with section 15 of the Oil Sands Conservation Regulations, except that the word "well" in subsection 1(b) shall be replaced by the phrase "well, well pad, or other appropriate grouping of wells" to provide for group production reporting.

4.7 Production Operations

The licensee or operator shall comply with section 39 of the Oil Sands Conservation Regulations, except

(1) subsection (1) requiring application and approval of the method for determining well-level production is amended by replacing the word "well", as it pertains to production, with the phrase "well, well pad, or other appropriate grouping of wells",

(2) subsection (2) requiring a procedure for allocating production back to individual wells is amended by replacing the word "wells" with the phrase "wells or groups of wells", and

(3) the licensee or operator shall be exempt from subsection (2) of section 39 where it can be shown to the satisfaction of the Board that allocation of production back to individual wells or groups of wells is not needed for royalty, equity, or engineering purposes.

4.8 Records and Reports of Operations and Production

The licensee or operator shall comply with section 12.030 of the Oil and Gas Conservation Regulations, except the word "well", as it pertains to production, shall be replaced by the phrase, "well, battery, or group of wells" to provide for battery or group production reporting.

4.9 Daily Record and Reporting

The licensee or operator shall comply with Section 44 of the Oil Sands Conservation Regulations, except the word "well", as it pertains to production, shall be replaced by the phase, "well, well pad, or other appropriate grouping of wells" to provide for group level production reporting.

4.10 Reporting from a Facility

The licensee or operator shall comply with section 45 of the Oil Sands Conservation Regulations, except the licensee or operator shall be exempt from the requirement to prorate production among the individual wells or groups of wells where it can be shown to the satisfaction of the Board that such proration is not needed for royalty, equity, or engineering purposes.

4.11 Common Flow Lines

The licensee or operator shall comply with section 7.020 of the Oil and Gas Conservation Regulations, except subsection (3) is amended as follows:

- common flow lines may be used without approval where the

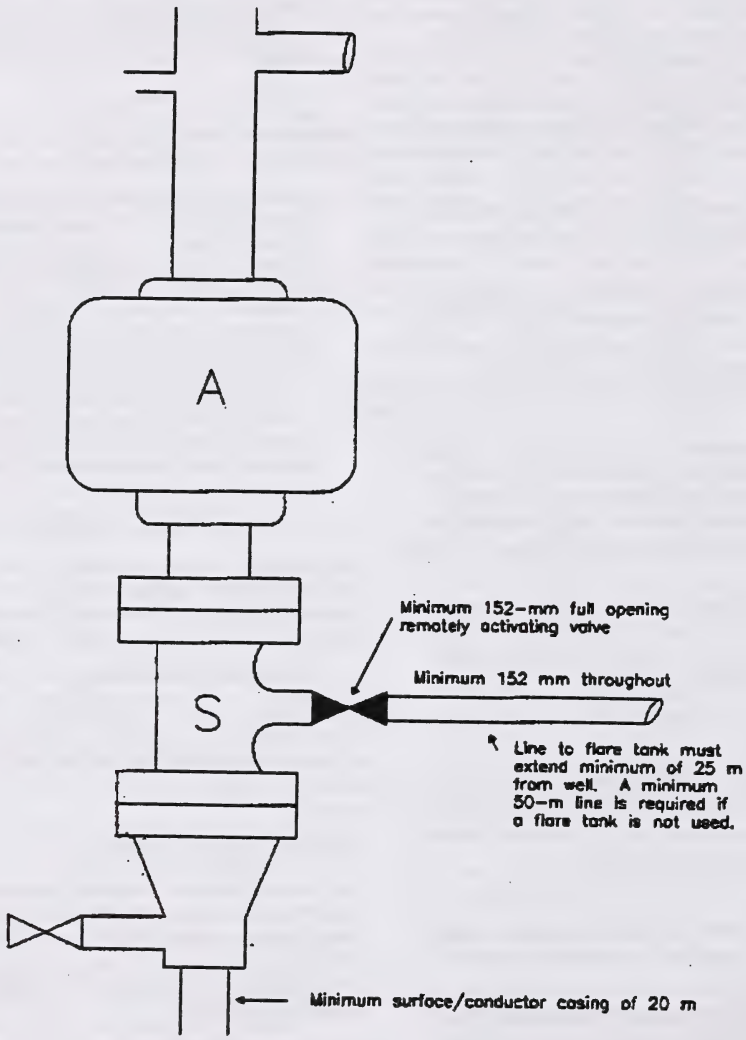
reporting of production has been approved on a well group or battery basis.

Also, the licensee or operator shall comply with section 40 of the Oil Sands Conservation Regulations, except

- common flow lines may be used without approval where reporting of production has been approved on the basis of a well pad or other appropriate grouping of wells.

FIGURE II

DRILLING BLOWOUT PREVENTION SYSTEMS – CLASS IA FOR HEAVY OIL AND OIL SANDS

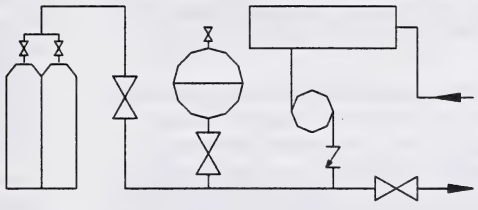

A
S
Minimum 152–mm full opening remotely activating valve
Minimum 152 mm throughout
Line to flare tank must extend minimum of 25 m from well. A minimum 50–m line is required if a flare tank is not used.
Minimum surface/conductor casing of 20 m

NOTE:

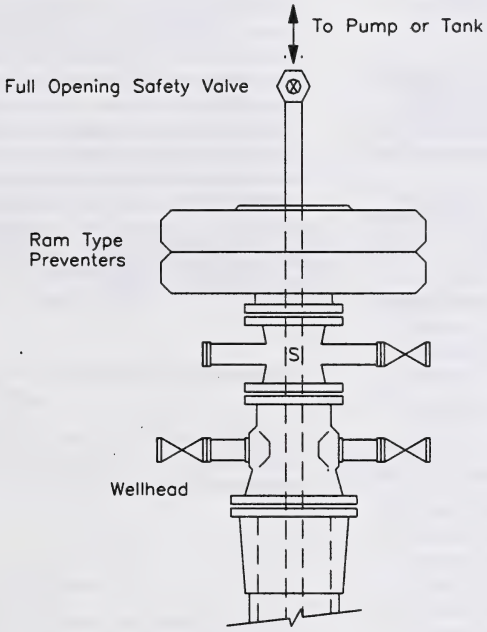
1. Flanged or welded connections are not mandatory.
2. A manifold is not required.

FIGURE III

SERVICING BLOWOUT PREVENTION SYSTEMS—CLASS IIA
Bottom-hole or injection pressure less than or equal to 21 000 kPa
H_2S release rate is less than 0.001 m^3/s



ACCUMULATOR SYSTEM



BLOWOUT PREVENTION STACK

Note:

1. Pressure rating of preventers is equal to or greater than formation or injection pressure.
2. The positioning of tubing and blind rams may be interchanged.
3. The preventer connection to the wellhead may be threaded.
4. If spool installed, the valve connection to spool may be threaded.
5. A flanged blowout preventer port (and valve) below the lowest set of rams may replace spool (valve may be threaded) on primary wells.
6. All threaded connections to the working spool shall be backwelded.
7. 50-mm kill line is required during the servicing of a secondary recovery well.

ID 91-6: Casing, Cementing, Sampling and Logging Requirements Senex, Kidney, Trout, and Associated Areas

26 July 1991

TO: All Oil, Gas, and Oil Sands Operators

The Alberta Energy and Utilities Board has been monitoring the drilling of wells within the severe lost circulation and oil sands areas outlined on the attached map. In addition to the lost circulation problem the EUB is concerned about the bitumen bearing oil sands, more specifically, whether the oil sands exist in commercial amounts and whether the oil sands are being adequately protected or isolated for future development.

In accordance with good drilling practice, operators have been setting surface casing at or near the top of the Upper Devonian (Wabamun) before drilling into the lost circulation zone. Intermediate casing is then set over the lost circulation zone and the bottom portion of the casing is cemented up to the lost circulation zone. The problem is that there are no open-hole logs over either the surface or the intermediate hole and as a result virtually no information is available on the oil sands zone. In addition, it is felt that in at least some wells, the oil sands and the lost circulation interval in the Upper Devonian (Wabamun) are left in communication.

The EUB believes that geological information on the Lower Cretaceous is required to determine the magnitude of the hydrocarbon resources and to ensure that those resources, when present, are adequately isolated. In view of this, the following requirements have been developed in conjunction with industry for the drilling of surface hole in these areas:

1. Conductor pipe is required to a depth of 20 m while drilling surface hole so that drilling returns may be sampled in order to identify the oil sands zones.

2 A Class I BOP or diverter system is required while drilling surface hole.

3. Drill cuttings (samples) will be required from 200 m to the top of the Upper Devonian (Wabamun) in all cases except where approval to waive this requirement has been obtained prior to issuance of the well licence.

4. Operators must have qualified personnel on site to evaluate the samples and to determine the appropriate surface casing setting depths.

5. If possible, the surface casing must be run to a depth below the bitumen bearing oil sand zone. It is recognized that in areas where the oil sands directly overlies the Upper Devonian (Wabamun) this may not be practical, as normally surface casing is set prior to penetration of the Wabamun lost circulation zone. As a minimum, the licensee must set surface casing to within 10 m of the Wabamun top on development wells and to within 20 m of the Wabamun top on exploration wells.

6. The surface casing must be cemented with thermal cement from the surface casing shoe to surface when oil sands are present.

7. From the effective date of this interim directive, an open-hole log or previously approved alternative logging program is required for the surface hole of the first well drilled in each quarter township. This requirement will be reviewed once enough data has been obtained to conduct a reasonable evaluation of bitumen potential within the area. At that time, a decision will be made whether to continue this requirement, require logging at a greater frequency, or, in the absence of significant crude bitumen reserves cancel this requirement.

In the event the licensee can show that it is possible to cement over the lost circulation zone then flexibility exists in connection with the surface casing setting depth.

ID 92-1: Drilling Blowout Prevention Requirements Modification

23 March 1992

TO: All Oil and Gas Operators

All Drilling Rig Contractors

Well control incidents over the past 10 years were reviewed and the existing blowout prevention requirements were evaluated. The review revealed some concerns about the overall level of kick occurrences and an increase in serious well control incidents at shallow wells. The EUB believes that some modifications to the existing blowout prevention requirements will be effective in reducing both the number of kicks and the severity of any subsequent well control incident. These modifications have been developed in consultation with the Drilling and Completions Committee (DACC). Representatives of DACC have concurred with the requirements set out in this directive.

The requirements of this directive are modifications of, or additions to, sections 8.130 to 8.143 of the Oil and Gas Conservation Regulations.

For a particularly difficult well control area, thirty-six townships in Southeastern Alberta, all wells being drilled to the Mannville Formation or deeper will have some special requirements.

Although the EUB encourages industry to comply with these requirements as soon as possible, it will not be proceeding with the formal regulation changes immediately. The introduction of these proposed changes, at this time, is intended to give industry an opportunity to try out these new procedures and to identify any shortcomings or the need for further modifications. Many operators have already incorporated these requirements into their operations. With the exception of the trip tank sizing specified in subsection 1.3.2, the EUB will begin enforcing the directive on 1 July 1992. The requirements of subsection 1.3.2 will be enforced commencing on 1 January 1993.

1.1 General

The following requirements have been categorized according to their respective roles in blowout prevention.

Sections 1.2 and 1.6 will require the enactment of entirely new sections of the Oil and Gas Conservation Regulations. The remainder of the requirements are intended only to modify certain existing regulations.

1.2 Kick Prevention

This requirement is a proposed new regulation.

Research of offset well records shall be conducted prior to making application for a well licence. This information shall be used to determine maximum pore pressures and hole problems expected in the proposed well, and to design the well and drilling program accordingly. This information shall be made available to the EUB upon request but does not have to be submitted with the well licence application.

1.3 Kick Detection

The licensee shall comply with section 8.137 of the Oil and Gas Conservation Regulations with the following additions:

1.3.1 If potential hydrocarbon-bearing zones have been penetrated, either a bottoms-up circulation shall be conducted or a weighted tripping pill shall be pumped prior to pulling pipe from the well. In addition, a 5-minute flow check shall be conducted and recorded in the drilling log book at the following stages during trips:

(1) Trip-out

(a) After pulling the first 5 per cent of the drill pipe from the hole.

(b) At the mid-point depth of the wellbore.

(c) Prior to pulling the first stand of drill collars from the hole.

(d) After all of the drill string is pulled out of the hole.

(2) Trip-in

(a) Upon reaching the surface casing shoe with the drill string.

(b) At the mid-point depth of the wellbore.

1.3.2 For rigs drilling Class III wells, the trip tank design must be such that a change in level of 25 mm equals a volume change of not more than 0.075 m^3. This equates to a maximum surface area of 3.0 m2. Alternatively, trip tanks with larger surface areas would be permitted if equipped with an electronic trip tank monitoring device capable of showing volume changes of 0.03 m^3 or less, in the oversized tank.

1.3.3 The driller shall at all times know the normal fluid level in the mud tanks as indicated by the pit level indicator. Alternatively, an electronic pit volume totalizer shall be installed.

1.4 Bleed-off Equipment Integrity

The licensee shall comply with section 8.141 of the Oil and Gas Conservation Regulations with the following addition:

1.4.1 Prior to assembly, all connections between the choke manifold and the mud-gas separator and between the choke manifold and the end of the flare line shall be visually inspected. After assembly of the connections, an inspection shall be conducted to ensure proper make-up. The results of the inspections shall be recorded in the drilling log book.

1.5 Supervision

The licensee shall comply with section 8.142 of the Oil and Gas Conservation Regulations with the following addition:

1.5.1 Except for wells in Class I, Class IA*, and Class II, if potential hydrocarbon-0bearing zones have been penetrated, either the rig manager or the licensee's representative shall be on site while tripping in or out of the well. This person shall possess a valid Second Line Supervisor's Well Control Certificate. However, if it is necessary to make an unscheduled trip when neither of these individuals is present, the trip may commence immediately after contacting the qualified individual. This individual shall then return to the well site immediately.

1.6 Specific High Hazard Area of Southeastern Alberta

The licensee shall comply with the following requirements in addition to all of the existing sections 8.130 to 8.143 of the Oil and Gas Conservation Regulations. Because of the high frequency of serious well control incidents within Townships 19 to 24 in Ranges 5 to 10 West of the 4th Meridian, a thirty-six-township area illustrated on the attached map (Appendix I) the following special requirements apply to all wells being drilled in this area to the Mannville Formation or deeper:

1.6.1 Surface casing shall be run to a minimum depth of 180 m.

1.6.2 Where fluid turns or high-pressure flexible hose exists in the section of the choke line between the blowout preventer stack and the choke manifold, an extra flare line for emergency purposes shall be installed. This line shall be installed upstream of the first fluid turn or high-pressure flexible hose and shall extend directly to the flare pit. The configuration is illustrated in Appendix II.

1.6.3 The emergency flare line shall,

(1) up to and including the last valve in this line, consist of an arrangement of valves and steel line which has a working pressure equal to the blowout preventer stack,

(2 be equal in diameter to the main flare line extending from the choke manifold,

(3 contain only straight pipe or 1.57-radian (90-degree) bends constructed of tees and crosses blocked on fluid turns, and

(4 be securely tied down.

1.6.4 After penetration of the Mannville Formation, the drilling fluid density shall be adequate to exert a minimum overbalance pressure of 1400 kPa at the Mannville Formation prior to tripping pipe out of the hole.

Appendix I High Hazard Area ID 92-1

Appendix II BOP High-Hazard Area ID 92-1

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* As defined in the Heavy Oil/Oil Sands Interim Directive ID 91-3.

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